State of California
Environmental Protection Agency
AIR RESOURCES BOARD

CALIFORNIA'S CAP-AND-TRADE PROGRAM

FINAL STATEMENT OF REASONS

October 2011

Table of Contents

State of California
California Environmental Protection Agency
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Final Statement of Reasons for Rulemaking, Including Summary of Public Comments and Agency Responses

PUBLIC HEARING TO CONSIDER ADOPTION OF A PROPOSED CALIFORNIA CAP ON GREENHOUSE GAS EMISSIONS AND MARKET-BASED COMPLIANCE MECHANISMS REGULATION, INCLUDING COMPLIANCE OFFSET PROTOCOLS

Public Hearing Date: December 16, 2010
Agenda Item No.: 10-11-1

I. GENERAL

A. Action Taken in This Rulemaking

In this rulemaking, the Air Resources Board (ARB or the Board) is adopting a new regulation to implement a California cap-and-trade program. The regulation was developed pursuant to the requirements of the California Global Warming Solutions Act of 2006, also known as Assembly Bill 32 (AB 32). The regulation is codified at sections 95800 to 96023, Title 17, California Code of Regulations (CCR). The cap-and-trade regulation will reduce greenhouse gases (GHG) from major emission sources (covered entities) by setting a firm cap on GHG emissions while employing market mechanisms to cost-effectively achieve the emission reduction goals. The cap for GHG emissions from major sources will commence in 2013 and decline over time, achieving GHG emissions reductions throughout the program's duration. The cap is measured in metric tons of carbon dioxide equivalent ($MTCO_2e$). Covered entities will be allocated some permits to emit (allowances), able to buy allowances at auction, purchase allowances from others, or purchase offset credits.

The cap-and-trade program will establish the total amount of GHG emissions that major sources would be allowed (permitted) to emit in the aggregate. ARB will distribute allowances to emit GHG emissions. The total number of allowances created would be equal to the total aggregate cap amount set for cumulative emissions from all covered entities. Each allowance will permit the holder to emit one $MTCO_2e$ of GHG.

Starting in 2012, the proposed regulation will include major GHG-emitting sources, such as electricity generation (including imports), and large stationary sources (e.g., refineries, cement production facilities, oil and gas production facilities, glass manufacturing facilities, and food processing plants) that emit more than 25,000 $MTCO_2e$ per year. The program will expand in 2015 to include fuel distributors (natural gas and propane fuel providers and transportation fuel providers) to address emissions from transportation fuels, and from combustion of other fossil fuels not directly covered at large sources in the initial phase of the program.

The years 2013 and 2014 are known as the “first compliance period,” and the years 2015–2017 are known as the “second compliance period.” The first compliance period would include sources responsible for more than one-third of the economy-wide GHG emissions in California. Starting with the second compliance period, the program would include sources responsible for about 85 percent of GHG emissions.

The rulemaking was initiated by the October 28, 2010, publication of a notice for a public hearing scheduled on December 16, 2010. A Staff Report: Initial Statement of Reasons, entitled “Proposed Regulation to Implement the California Cap-and-Trade Program” (Staff Report or ISOR) was also made available for public review and comment starting October 28, 2010. The Staff Report, which is incorporated by reference herein, contains an extensive description of the rationale for the proposal. These documents were also posted October 28, 2010, on ARB’s internet site for this rulemaking at: http://www.arb.ca.gov/regact/2010/capandtrade10/capandtrade10.htm.

On December 16, 2010, the Board conducted a public hearing to consider the staff’s proposal as set forth in the Staff Report. During the comment period that commenced on November 1, 2010, and ended at noon on December 15, 2010, the Board received 800 separate written comments and multiple copies of form letters. At the hearing the Board received oral testimony from 150 persons and an additional 35 written statements and other submittals.

At the conclusion of the hearing, the Board adopted Resolution 10-42, in which it directed the Executive Officer to take several actions including making the originally proposed regulation with a number of proposed modifications available for formal public comment. Staff suggested these modifications in response to public comments made after issuance of the original proposal. The text or narrative description of each modification was contained in a nine-page document entitled, “Public Hearing to Consider Adoption of a Proposed Regulation to Implement a California Cap-and-Trade Program–Staff’s Suggested Modifications to the Original Proposal,” which was distributed at the beginning of the hearing and included as Attachment B to Resolution 10-42. In addition, staff released a document entitled, “Appendix 1: Staff Proposal for 15-day Changes to Address Electricity Sector Allowance Allocation,” which was also released at the Board Hearing on December 16, 2010. Appendix 1 includes staff’s proposal on subsequent 15-day changes to address electricity sector issues.

Resolution 10-42 directed the Executive Officer to incorporate the modifications described in Attachment B into the originally proposed regulatory text, with such other conforming modifications as may be appropriate. The Executive Officer was directed to make the modified regulation (with the modifications clearly identified) and any additional documents or information available for a supplemental public comment period. He was also directed to consider any comments on the modifications received during the supplemental comment period. The Executive Officer was then directed to (1) adopt the modified regulation as it was made available for public comment, with any appropriate additional non-substantial modifications; (2) make additional modifications available for public comment for an additional period of at least 15 days; or (3) present the regulation to the Board for further consideration if he determined that this is warranted.

In preparing the modified regulatory language, the staff made various additional conforming revisions in an effort to best reflect the intent of the Board at the hearing. The staff also identified several additional conforming modifications that are appropriate in order to make the regulation work as effectively as possible. These post-hearing modifications were incorporated into the text of the proposed regulation, along with the modifications specifically identified in Attachment B to Resolution 10-42.

The text of the proposed modifications to the regulation, with the modified text clearly indicated, was made available for a supplemental 15-day comment period starting on July 25 and ending on August 11, 2011 at 5:00 p.m., by issuance of a Notice of Public Availability of Modified Text and Availability of Additional Documents and a "Modified Regulation Order" containing the modified regulatory text (the First Notice of Modified Text). Additional documents (Appendix A *Staff Proposal for Allocating Allowances to Electricity Distribution Utilities*, and Appendix B *Development of Product Benchmarks for Allowance Allocation*) were also posted on ARB's internet site on July 25, 2011. Appendix A was subsequently revised and re-posted on July 27, 2011. ARB received 192 written comments during the supplemental comment period ending August 11, 2011 at 5:00 p.m.

In light of the supplemental comments received during the first 15-day change comment period, the Executive Officer determined that additional modifications were appropriate. A Second Notice of Public Availability of Modified Text (the Second Notice of Modified Text) and a "Modified Regulation Order" containing the modified regulatory text (the Second Modified Text Document) were posted September 12, 2011, on ARB's Internet site for the rulemaking. The second 15-day change comment period ended September 27, 2011, at 5:00 p.m., by which time 114 additional written comments were received.

With respect to each of the two notices of modified text, on the Internet posting date the notices and all attachments were mailed to four parties for whom ARB staff did not have electronic mail addresses, as required by section 44(a), title 1 CCR. At the same time, the notices and all attachments were electronically distributed to all other parties identified, per section 44(a), title 1, CCR, in accordance with Government Code section 11340.85, and to all persons that have subscribed to the following ARB's listserves (number of subscribers are provided in parentheses): capandtrade10 (1,315), capandtrade (4,976), cc (7,921), ghg-rep (3,348), and ghg-ver (3,798).

After considering the comments received during the supplemental comment periods, the Executive Officer determined that it was appropriate to present the modified regulatory language to the Board for further consideration. Subsequently, on October 20, 2011, the Board considered the modified regulatory language and adopted the cap and trade regulation. The adopted regulation reflects the final modifications that were made available for the two supplemental comment periods. The following sections are affected by the adoption of California Code of Regulation, title 17, subchapter 10, new article 5, which contains new sections 95800, 95801, 95802, 95810, 95811, 95812, 95813, 95814, 95820, 95821, 95830, 95831,95833, 95834 95832, 95840, 95841, 95841.1, 95850, 95851, 95852, 95852.1, 95852.1.1, 95852.2, 95853, 95854, 95855, 95856, 95857,95858, 95870, 95890, 95891, 95892, 95893, 95910, 95911, 95912, 95913, 95914, 95920, 95921, 95922, 95940, 95941, 95942, 95943, 95970, 95971, 95972, 95973, 95974, 95975, 95976, 95977, 95977.1, 95977.2, 95978, 95979, 95980, 95980.1, 95981, 95981.1, 95982, 95983, 95984, 95985, 95986, 95987, 95988, 95990, 95991, 95992, 95993, 95994, 95995, 95996, 95997, 96010, 96011, 96012, 96013, 96020, 96021, 96022, and 96023.

This Final Statement of Reasons (FSOR) includes only comments directed toward the regulation, and updates the Staff Report by identifying and providing the rationale for the modifications made to the originally proposed regulation. The FSOR also contains a summary of the comments received on the proposed new regulation during the formal regulatory process and ARB's responses to those comments.

B. Incorporation of Materials by Reference

The following documents are incorporated by reference in the regulation:

(1) ASTM 6751-08, "Standard Specification for Biodiesel Fuel Blendstock (B100) for Middle Distillate Fuels," approved September 15, 2007, revised October 1, 2008;

(2) ASTM D1835-05, "Standard Specification for Liquefied Petroleum (LP) Gases," April 1, 2005;

(3) ASTM D6751-09a, "Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels," approved September 15, 2007, revised October 1, 2008;

(4) ASTM D6866-10, "Standard Test Methods for Determining the Biobased Content of Solid, Liquid, and Gaseous Samples Using Radiocarbon Analysis," August 6, 2010; and

(5) Z'berg-Nejedly Forest Practices Act of 1973, as amended January 1, 1998.

(6) The California Energy Commission's *Guidelines for California's Solar Electric Incentive Programs,* Third Edition, June 2010. This document can be accessed at: http://www.arb.ca.gov/regact/2010/capandtrade10/2ndguidelines.pdf.

The following documents are ARB-drafted documents that are were incorporated by reference into the cap-and-trade regulation when it was adopted on October 20, 2011. These documents were considered by the Board at the December 16, 2010 public hearing and any subsequent modifications to the documents were made available during the first and second 15-day change comment periods in accordance with the

Administrative Procedure Act (Government Code section 11340 et seq.). The final date of these documents will be the date of approval by the Office of Administrative Law.

- Compliance Offset Protocol U.S. Forest Projects
- Compliance Offset Protocol Livestock Projects
- Compliance Offset Protocol Ozone Depleting Substances Projects
- Compliance Offset Protocol Urban Forest Projects

C. Supporting Documents and Information

In accordance with Government Code section 11347.1, ARB has added to the rulemaking record the following documents that support the proposed action:

Staff Proposal for Allocating Allowances to the Electricity Distribution Utilities: This document describes the process ARB staff used to gather utility data and the assumptions made in projecting utility resource profiles, explains the proposed method for allocating allowances to the electricity sector, and clarifies which entities are eligible to receive allocations reserved for the electricity sector. The document can be accessed at: http://www.arb.ca.gov/cc/capandtrade/meetings/072011/electricity-allocation.pdf.

Development of Product Benchmarks for Allowance Allocation: This document describes the framework for establishing the benchmarks for allowance allocation for industrial products. This document can be accessed at: http://www.arb.ca.gov/cc/capandtrade/meetings/072011/product-benchmarks.pdf.

Additionally, it was clarified that certain economic analysis documents were made available during the 45-day public comment period but inadvertently left out of the original public notice listing of available documents. One relates to the compliance pathway analysis related to boilers contained in the Proposed Regulation to Implement the California Cap-and-Trade Program: Supplemental Materials for the Compliance Pathways Analysis (Staff Report Chapter V and Appendix F). The other relates to the compliance pathway analysis related to process heaters also contained in the Proposed Regulation to Implement the California Cap-and-Trade Program: Supplemental Materials for the Compliance Pathways Analysis (Staff Report Chapter V and Appendix F). Both of these documents can be accessed at: http://www.arb.ca.govregact/2010/capandtrade10/capandtrade10.htm.

The addition of the above noted documents to the record was announced in the first 15-day notice, and the notice invited public comment on the addition of these documents to the record.

In the second 15-day notice, two additional documents were either added to the rulemaking record or incorporated into the regulation, and the notice invited public comment on the addition of these documents. They are:

- Appendix A to Second 15-Day Cap-and-Trade Regulatory Text: Refinery Allocation Methodology. This document can be accessed at: http://www.arb.ca.gov/regact/2010/capandtrade10/2nd15dayappa.pdf.

- The California Energy Commission's *Guidelines for California's Solar Electric Incentive Programs,* Third Edition, June 2010. This document can be accessed at: http://www.arb.ca.gov/regact/2010/capandtrade10/2ndguidelines.pdf.

D. Fiscal Impacts

The Executive Officer has determined that the proposed regulatory action would create costs or savings, as defined in Government Code sections 11346.5(a)(5) and 11346.5(a)(6), to State agencies or in federal funding to the State. The proposed regulatory action would create costs and would impose a mandate on some State and local agencies, but would not create costs or impose a mandate on school districts. Seven California public universities, the California Department of Water Resources (DWR), several municipal utilities and one county correctional facility would have a compliance obligation under the proposed regulation. These entities would be required to surrender allowances or offsets equal to the amount of their GHG emissions during the compliance period.

Because the regulatory requirements apply equally to all covered entities and unique requirements are not imposed on local agencies, the Executive Officer has determined that the proposed regulatory action imposes no costs on local agencies that are required to be reimbursed by the State pursuant to part 7 (commencing with section 17500), division 4, title 2 of the Government Code, and does not impose a mandate on local agencies or school districts that is required to be reimbursed pursuant to section 6 of article XIII B of the California Constitution.

The Board's Executive Officer has also determined that pursuant to Government Code Section 11346.5(a)(5), the regulatory action will affect small businesses. Because very few small businesses have enough emissions to be regulated directly under the cap-and-trade program, most foreseeable small business impacts will result from changes in energy expenditures. An analysis on how implementation of the program could affect expenditures that small businesses make on electricity and natural gas, and how such shifts could affect their profitability, demonstrated that most sectors would experience less than a two percent change in the share of revenue spent on energy and are not likely to face competitiveness issues relative to out-of-state businesses. A detailed description of these impacts is included in Chapter VIII and Appendix N of the Staff Report.

E. Consideration of Alternatives

A discussion of alternatives to the initial regulatory proposal is found in Chapter IV of the Staff Report. Specifically, the following alternative approaches were considered by the Board:

- Do not implement the cap-and-trade program, and do not replace it with an alternate approach to achieve additional emissions reductions (no project).
- Implement additional source-specific regulations designed to achieve the AB 32 goals in place of the cap-and-trade program.
- Implement a carbon fee in place of the cap-and-trade program.
- Link a California cap-and-trade program to a federal cap-and-trade program.

For the reasons set forth in Chapter IV of the Staff Report, in staff's comments and responses at the hearings, and in the FSOR, the Board has determined that none of the alternatives considered by the agency or that have otherwise been identified and brought to the attention of the agency would be more effective in carrying out the purpose for which the regulatory action was proposed or would be as effective and less burdensome to affected private persons than the action taken by the Board.

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II. MODIFICATIONS MADE TO THE ORIGINAL PROPOSAL

The following discussion addresses all substantive modifications made to the originally proposed regulatory text. It does not include modifications to correct typographical and citation errors, numbering errors, grammar errors, or the rearranging of sections and paragraphs for structural improvements; nor does it include all of the minor revisions made to improve clarity. These modifications were explained in detail in the Notices of Public Availability of Modified Text; the first which was issued for a 15-day public comment period beginning on July 25, 2011, and ending on August 11, 2011, and the second which was issued for a 15-day public comment period beginning on September 12, 2011, and ending on September 27, 2011.

Part A. below summarizes the modifications and the rationale for the changes made in the 1st 15-Day Change Notice. Part B. summarizes the modifications and the rationale for the changes made in the 2nd 15-Day Change Notice.

A. First 15-day Changes

1. Purpose (Section 95801)

No modifications made to this section.

2. Definitions (Section 95802)

Several definitions were added or modified. Many of the new or modified definitions are necessary to implement the "first deliverer" approach for the electricity sector, as well as to implement the benchmarking approach for distribution of allowances for several different sectors. Definitions were also added or modified to improve clarity and to ensure that the terms used in the cap-and-trade regulation are consistent with those used in the Mandatory Reporting of Greenhouse Gas Emissions Regulation (MRR). Adding these definitions was required to ensure that all terms contained in the regulation have the same meaning to the regulated public.

Section 95802 was modified to include a definition for "carbon dioxide supplier," "geologic sequestration," and "process unit" to reflect changes to sections 95812(c)(3) and 95852(g).

3. Covered Gases (Section 95810)

No modifications made to section 95810.

4. Covered Entities (Section 95811)

Section 95811 specifies which entities are covered by the regulation. One modification was made to section 95811(g) which specifies that suppliers of carbon dioxide (CO_2) will be referred to as "carbon dioxide suppliers" for purposes of the regulation. This change was made to simplify the regulation such that only one term would be used for carbon dioxide suppliers instead of multiple terms (e.g., suppliers of carbon dioxide, suppliers of CO_2, carbon dioxide suppliers, CO_2 suppliers).

5. Inclusion Thresholds for Covered Entities (Section 95812)

Section 95812(a) was modified to specify that reported and verified annual emissions must be reported and verified pursuant to the verification sections of the MRR. This modification is necessary to be consistent with the MRR, and to clarify that a covered entity's annual emissions must both be reported and verified.

Section 95812(b) was modified to specify that an entity will be classified as a covered entity if the reported or reported and verified annual emissions in any data year from 2008 to 2011 exceed the thresholds identified in sections 95812(c) and (d), and to remove the term "aggregated." This modification is necessary to be consistent with the MRR.

New section 95812(c) was modified to clarify the existing applicability thresholds for covered entities.

New section 95812(c)(3) was added to replace original section 95812(c) and specify that the inclusion threshold for carbon dioxide suppliers is based on the amount of CO_2 captured from production process units and production wells, and supplied for commercial application or geologic sequestration. This change was required to ensure that all CO_2 created and potentially emitted in California by carbon dioxide suppliers would be covered, and to align with the federal greenhouse gas reporting regulation.

New section 95812(c)(4) was inserted to be consistent with how the MRR categorizes these sources for reporting purposes.

Section 95812(d) was modified to include assigned emissions levels consistent with the MRR. This change is necessary so covered entities that do not receive a positive verification are still included in the regulation.

Section 95812(d)(2) was modified to be consistent with the changes made to section 95812(c)(2).

Various other minor and non-substantive clarifications were also made to section 95812.

6. Opt-In Covered Entities (Section 95813)

Minor and non-substantive clarifications were made to section 95813 to better organize the section and otherwise clarify who can be an opt-in covered entity.

7. Voluntarily Entities and Other Registered Participants (Section 95814)

Original section 95814(a)(1) was deleted and folded into section 95814(a). Original sections 95814(a)(2), (a)(2)(A), and (a)(2)(B) were replaced with new sections 95814(a)(1) and (2) to make the section more clear.

New section 95814(a)(3) creates a new type of voluntarily associated entity (VAE) that will take only temporary control of compliance instruments when it provides clearing services for transactions. Defining this new VAE allows ARB to specify a new type of account that can only be used by that type of entity, which ARB can then conditionally exempt from the holding limit. This section specifically adds derivatives clearing organizations registered with the U.S. Commodity Futures Trading Commission as eligible. Staff is requesting comment on whether the new VAE category captures the types of clearing entities expected to be active in carbon markets.

Section 95814(b)(1)(D) was modified to specify that entities approved as Early Action Offset Programs, pursuant to subarticle 14, do not qualify to hold compliance instruments, but may qualify as a Registered Participant. This modification was necessary to ensure consistency between Offset Project Registries and Early Action Offset Programs, as, in many cases, they may be the same entities.

8. Compliance Instruments Issued by the Air Resources Board (Section 95820)

Section 95820(a)(3) was modified to remove the requirement for the Executive Officer to place allowances into a holding account within 15 days of the effective date of the regulation as it is unlikely there will be a system with a holding account available within 15 days to meet this requirement.

Minor and non-substantive clarifications were made to section 95820 to correct cross-references within the regulation.

9. Compliance Instruments Issued by Approved Programs (Section 95821)

Minor and non-substantive clarifications were made to section 95821 to add consistent terminology and correct cross-references within the regulation.

10. Registration with ARB (Section 95830)

Section 95830(b) was modified to delete references to linking to external programs approved by ARB. This text was deleted because any additional registration requirements will be addressed in subarticle 12 at the time the regulation is modified to include linkage.

New section 95830(c)(2) exempts entities registering to provide clearing services from having to meet the information disclosure requirements of 95830(c)(1)(D) for the compliance instruments it holds for the purposes of clearing transactions. This provision was added to avoid burdening entities providing clearing services with having to report transaction information that ARB will be getting directly from the entities involved in a transaction.

Section 95831(d)(1)(A) was modified to change the timing for registration from 45 days to 30 days because 30 days gives entities enough time to submit all the information needed to register. Section 95831(d)(1)(B) was modified to change the auction timing due to the change in compliance obligation start date from 2012 to 2013.

New section 95830(f) adds the requirement that registered entities must update their registration information within 10 days of a change in that information. The section allows ARB to revoke, suspend, or restrict an entity's registration or impose penalties if an entity fails to update its registration information. This section is necessary because ARB will rely on registration information to conduct market oversight and enforce rules on holding and purchase limits. These efforts will be undermined if entities are not required to update the information.

New section 95830(g) adds provisions concerning the confidentiality of the information gathered through registration. New section 95830(g)(1) identifies beneficial holdings disclosures and information on the identity of real persons as information that should be treated as confidential. Section 95830(g)(2) allows for other registration information to be made public. ARB is proposing these conditions to balance the need for market transparency with the protection of information on individuals.

11. Account Types (Section 95831)

New section 95831(a)(5) creates a new type of holding account, called an Exchange Clearing Holding Account, for entities providing exchange clearing services. Entities transfer compliance instruments to clearing entities on a temporary basis while a transaction is being cleared. The clearing entity then transfers the compliance instruments to the designated account of the entity receiving the allowances as part of the transaction being cleared. Creating this account will allow ARB to exempt an entity clearing transactions from the holding limit.

Original section 95831(b) was moved to new section 95921(f), because the text deals with account restrictions that may be imposed for rule violations, and that section deals with the conduct of trading.

Original section 95831(c)(5), now section 95831(b)(5), was modified to clarify how the Forest Buffer Account functions and when ARB may place ARB offset credits into the Retirement Holding Account from the Forest Buffer Account. These changes were made for clarification purposes and to align these requirements with the updated requirements in section 95983.

New section 95831(b)(6) creates a holding account, called the Voluntary Renewable Electricity Reserve Account, under the control of the Executive Officer. This provision is needed to implement section 95870(c). The Executive Officer will place allowances into the account, which may then be retired as part of the voluntary renewable energy set-aside. The account will be closed when the allocation of allowances is depleted.

Various other minor and non-substantive clarifications were made to section 95831 to add and correct cross-references within the regulation.

12. Designation of Authorized Account Representative (Section 95832)

Sections 95832(a)(4), 95832(a)(6), and 95832(d) were modified to specify that an authorized account representative and any alternative account representative must attest to the validity of their application for an account with the accounts administrator under penalty of perjury and under the laws of the State of California. This addition is necessary to ensure that all information submitted is true and complete under penalty of perjury.

Various minor and non-substantive clarifications were also made to section 95832 to correct cross-references within the regulation and to fix numbering.

13. Disclosure of Direct and Indirect Corporate Associations (New Section 95833)

New section 95833 is composed generally of modified text that originally appeared as sections 95914(a) through (d). In addition to moving these sections, staff made two changes to the original text. The section requires all registered entities to identify if they share specific types of relationships with other registered entities. This information is needed to monitor for suspicious activity in the market program and ensure market rules are not circumvented.

New section 95833(a)(2) was modified from original text to clarify an existing requirement that an entity holding compliance instruments on behalf of another entity in a beneficial holding relationship is considered to have a direct corporate association with the other entity. New section 95833(a)(4) was added to exempt from the corporate association requirements any entities already subject to state or federal rules which prohibit the sharing of market information between entities that have a formal corporate affiliation.

New sections 95833(d)(1) through (4) were moved from section 95914. No substantive changes were made to this text.

14. Disclosure of Beneficial Holding (New Section 95834)

New section 95834 provides detailed provisions for an existing requirement that any entity holding compliance instruments on behalf of another entity disclose the relationship to ARB. New section 95834(a)(1) defines when a beneficial holding relationship exists. Specifically, such a relationship can only exist between two registered entities. It also defines an agent as the entity holding allowances owned by a second entity, which is defined as the principal.

New section 95834(a)(2) creates a type of beneficial holding relationship for electrical distribution utilities that may need to hold compliance instruments on behalf of entities with whom they have electricity delivery contracts that may not explicitly determine which party to the contract has the responsibility to surrender compliance instruments. ARB has held extensive discussions with electric utilities on this issue, and is requesting comment on whether the proposed requirements address this concern.

New section 95834(a)(3) allows entities which have disclosed a corporate association pursuant to section 95833 to utilize the beneficial holding arrangements.

New section 95834(b) contains requirements for the disclosure of beneficial holding relationships. New section 95834(c) contains requirements applying to an entity that may serve as an agent for more than one principal. The requirements are necessary to prevent the disclosure of market information between market participants and to prevent opportunities for collusion.

15. Compliance Period (Section 95840)

Section 95840(a) was modified to exclude 2012 from the first compliance period and accommodate the new compliance obligation start date of January 1, 2013.

16. Allowance Budgets Calendar Years 2013–2020 (Section 95841)

Section 95841 was modified to remove the allowance budget for 2012 to accommodate the new compliance obligation start date of January 1, 2013.

17. Voluntary Renewable Electricity (New Section 95841.1)

New section 95841.1 was added to clarify the treatment of voluntary renewable electricity, reflecting the intended changes identified in Resolution 10-42 and in Attachment B of the resolution. Staff worked with stakeholders to clarify the role of voluntary renewable electricity in reducing greenhouse gas (GHG) emissions after the cap-and-trade program is in place, in order to support increased voluntary investment in renewable resources. “Voluntary renewable electricity” refers to renewable electricity that, unlike renewable electricity used for the Renewable Portfolio Standard, is not the subject of a mandate. Once the cap is set, voluntary renewable electricity can only reduce GHG emissions if it is tied to a reduction in the total amount of allowances. New section 95831(b)(6) explains that a Voluntary Renewable Electricity Reserve Account will be set up to hold allowances that may be retired to account for voluntary renewable electricity. This section explains what is required to demonstrate that Renewable Energy Credits (RECs) or renewable electricity is eligible to count toward the retirement of allowances from this account.

New section 95841.1(a) explains the program requirements for voluntary renewable electricity. It directs the end-user, the Voluntary Renewable Electricity (VRE) participant, or the entity acting on behalf of the end-user to meet the requirements of section 95841.1 in order to have the REC or electricity count toward retirement of allowances. This section also clarifies that the eligible electricity must meet California load.

New section 95841.1 (b) explains the reporting requirements, including required attestations that the end-user, or entity acting on behalf of the end-user claiming credit for the voluntary renewable electricity or the Renewable Energy Credit (REC), has not also authorized the use of the claim in any other program. This section also describes the reporting required to demonstrate the claimant's ownership and quantity of the renewable electricity or RECs, and what documentation is needed to apply for allowance retirement. The requirements include that the generator of voluntary renewable electricity be registered as eligible for the Renewable Portfolio Standard (RPS) with the California Energy Commission, to ensure that the voluntary renewable electricity meets the same standards required for the RPS. This section also requires VRE participants with claims to RECs or electricity from generators with a nameplate capacity of less than or equal to 200 kilowatts (kW) to aggregate with other participants. This requirement enables administrators to manage the number of applications and fractions of allowances to be retired.

New section 95841.1(c) describes how the amount of allowances to be retired is calculated.

New section 95841.1(d) provides that a generator or REC marketer will fulfill the attestation requirements of section 95841.1(b) if it participates in a tracking system that will be developed by ARB, once the tracking system is approved by the Executive Officer.

18. General Requirements (Section 95850)

New section 95850(b) was added to specify that a covered entity's compliance obligation is based on its verified emissions, rounded to the nearest whole ton, or their assigned emissions pursuant to the MRR. This modification is necessary to clarify that an entity's compliance obligation will be based on their verified emissions rounded to the nearest whole ton, in the case that an entity reports its emissions in decimal form.

Section 95850(c) was changed from requiring a 10-year data retention period to a 7-year period, to be consistent with the Western Climate Initiative (WCI) essential reporting requirements. Stakeholders also commented that a 10-year period is too long, given how much reporting data they must hold on to.

New section 95850(c)(4) requires that covered entities retain their detailed verification reports as required pursuant to the MRR for at least seven years. This was included to require that a covered entity retain all records associated with reporting and compliance obligations.

Various minor and non-substantive clarifications were made to section 95850 to ensure consistent terminology within the regulation.

19. Phase-in of Compliance Obligation for Covered Entities (Section 95851)

Various minor and non-substantive clarifications were made to section 95851 to correct cross-references and add consistent terminology within the regulation.

20. Emission Categories Used to Calculate Compliance Obligations (Section 95852)

Section 95852(a) was divided into subsections and modified to specify that a covered entity has a compliance obligation for assigned emissions. This modification was made to specify that if ARB has assigned emissions for the sources subject to a compliance obligation, then the facility will have a compliance obligation equal to the value of every $MTCO_2e$ of assigned emissions. New section 95852(a)(2) was included to specify that beginning in 2015, combustion emissions resulting from burning specific fuels are not included when calculating an entity's compliance obligation. This modification was made to clarify that the compliance obligation for these specified fuels is at the supplier level in 2015. These provisions apply only for stationary combustion, and not suppliers. These changes are necessary to ensure compliance obligations are calculated as accurately as possible.

Section 95852(b) was modified to specify how the compliance obligation is calculated for electricity marketers and retailers that import electricity, and for natural gas suppliers—who will subtract out the fuel supplied to entities subject to the cap (e.g., electricity generators) and whose obligation is based on the end user's combustion of the fuel. This modification was necessary to clarify the reference to the applicability section, and to explain that electricity deliveries are subject to the new provision prohibiting resource shuffling. In addition, the reference to thresholds was added to clarify that first deliverers have a compliance obligation only if they exceed the applicable threshold.

New section 95852(b)(1) was added to prohibit resource shuffling and minimize the potential for leakage. Leakage occurs if an entity providing electricity into California changes the identified source of the electricity, to a facility that utilizes a cleaner fuel or technology solely to claim a lower compliance obligation. In this scenario, the total actual emissions within the interconnected western electricity grid are not reduced. New sections 95852(b)(1)(A) and (b)(1)(B) contain the specific attestations that first deliverers must sign and deliver to ARB to certify that their deliveries do not include any resource shuffling. These sections work in conjunction with the newly added definition of "resource shuffling" in section 95802, and are necessary to ensure the integrity of the cap-and-trade program.

New section 95852(b)(2) clarifies that, in order to make a specified delivery claim, a first deliverer must report pursuant to the MRR, including reporting the facility's assigned identification number, and that first deliverers must be the facility operator or have ownership rights to the electricity generated by the facility. This section was added to clarify what a first deliverer must provide for it to claim a facility-specific emission factor for an electricity delivery. These sections are necessary to ensure integrity of the cap-and-trade program.

New section 95852(b)(3), in conjunction with a new definition for replacement electricity in section 95802, sets out requirements for claiming the emission factor of a variable renewable resource (wind, solar, or run-of-the-river hydroelectric) for “substitute” electricity that is delivered in place of the real-time generation. This provision is necessary to address utility concerns about the treatment of renewable electricity, and to strike a balance between recognizing the value of variable renewable electricity and limiting the possibility for double-counting of emission reductions in cases where electricity from a variable renewable resource cannot be directly delivered to California.

New section 95852(b)(4) requires direct delivery for electricity with a facility-specific emission factor lower than the default emission factor. “Direct delivery” is newly defined in section 95802. Section 95852(b)(4) is needed to ensure that claims for electricity from a specific facility are for electricity that is actually delivered to serve California load, and is not used to serve a load outside of California. This requirement is among those needed to prevent resource shuffling and leakage.

New section 95852(b)(5) requires that electricity generated from biomethane, in order to receive a zero emission factor, must meet reporting requirements pursuant to the MRR. This is added to ensure that claims for electricity from biomethane are supported by the reporting of all data necessary to demonstrate that the electricity is not subject to a compliance obligation.

In conjunction with a new definition of qualified exports, new section 95852(b)(6) allows a credit against a first deliverer’s compliance obligation based on emissions from electricity that is exported at the same time that the first deliverer is importing electricity. This provision is necessary to address stakeholder concerns regarding “simultaneous exchanges” and recognizes that this kind of exchange is similar to the wheeling of electricity through California, in that not all of the electricity being imported is actually used to serve California load.

New section 95852(b)(7) was added to include the equation for how ARB will assign a compliance obligation for electricity deliveries from jurisdictions that are not linked to the California program. Staff is seeking stakeholder input on the variables in the equation, and the equation itself, on how to assign a compliance obligation.

New sections 95852(c)(1) through (c)(4) were added to specify that suppliers of natural gas must report emissions delivered to all end users in California. These sections further specify that ARB will provide information that will enable the supplier of natural gas to subtract out the emissions attributed to covered entities for which it provides natural gas. This will leave the remaining balance of carbon dioxide equivalent (CO_2e) emissions that receive a positive or qualified positive emissions data verification statement or assigned emissions as the compliance obligation for the natural gas supplier. The amount of emissions subtracted for the covered entities as customers of the natural gas supplier will equal the amount of CO_2e emissions that received a positive or qualified positive emissions data verification statement or were assigned emissions. These sections were added to clarify how the compliance obligation will be determined for suppliers of natural gas.

Section 95852(d) was modified to specify that the compliance obligation for suppliers of petroleum products is not only for imports or deliveries into California. This is necessary to clarify what fuel delivery types are subject to a compliance obligation and which are not.

Section 95852(g) was modified to specify that carbon dioxide suppliers have a compliance obligation only for CO_2 produced in-state and either (1) supplied for in-state utilization, or (2) exported out-of-state for geologic sequestration. The compliance obligation for in-state supply of CO_2 was added because it was mistakenly omitted in the regulation. Carbon dioxide supplied for geologic sequestration can only be exempt from a compliance obligation if it is verified to be geologically sequestered through use of a Board-approved quantification methodology. Imports from carbon dioxide suppliers were excluded because CO_2 imports are relatively small and those imports would need free allocations to ensure similar treatment as in-state production of supplied CO_2. Instead of providing free allocation of allowances for a relatively small amount of CO_2, ARB chose to monitor imports; if CO_2 imports increase, ARB will reassess its treatment of imported CO_2. Exports were, for the most part, excluded from a compliance obligation because the potential emission of CO_2 would occur out of state. An exception is made for CO_2 exported for purposes of geologic sequestration (i.e., this CO_2 *will* have a compliance obligation) because ARB does not want to incentivize out-of-state geologic sequestration without rigorous assurance that the CO_2 will remain permanently stored underground.

Section 95852(h) was deleted and moved to new section 95852(i) to incorporate the correct numbering structure and put it at the end of section 95852.

New section 95852(h) was added to specify emissions categories used to calculate compliance obligations for oil and gas producers, to be consistent with the MRR for purposes of entities that report and hold a compliance obligation.

21. Compliance Obligations for Biomass-Derived Fuels (Section 95852.1)

Section 95852.1 was clarified to accurately reflect source categories and fuel types that have a compliance obligation, and that other biomass CO_2 reported under the MRR has a compliance obligation. This clarification is necessary to ensure that regulated entities' compliance obligations are correctly calculated.

22. Eligibility Requirements for Biomass-Derived Fuels (New Section 95852.1.1)

New section 95852.1.1(a) was added to require emissions from biomass-derived fuels to be verified under the MRR and receive a positive or qualified positive emissions data verification statement or assigned emissions to be exempt from a compliance obligation. These requirements were originally found in MRR section 95131(i)(1)(A); however, staff moved them into this section in the cap-and-trade regulation so that all provisions defining a compliance obligation are in one regulation.

New section 95852.1.1(a)(1) specifies that the contract shuffling date for purchasing any biomass-derived fuel must be in effect prior to January 1, 2012, and remain in effect or have been renegotiated with the same California operator within one year of contract expiration. This section is necessary to prevent contract shuffling wherein contracts are being diverted to California by entities seeking to avoid a compliance obligation for fossil fuels. Contract shuffling could allow fossil emissions to increase in states where the biofuel was previously combusted, which could result in no net change in emissions and emissions leakage. The January 1, 2012, date was changed from the original date in the MRR of January 1, 2010, in response to stakeholder comments that staff needed to allow time for contracts to go through the California Energy Commission (CEC) process for RPS certification.

New sections 95852.1.1(a)(1)(A) and (B) were added to provide the requirements that biofuel has to meet once a signed contract is in place. These sections are necessary to clarify how new and increased production for purposes of contract shuffling will be treated.

New section 95852.1.1(a)(2) was added to specify that fuel provided under any contracts after January 1, 2012, must be for additional biomass-derived capacity, and not a transfer of existing biomass fuel from out of state. This section is necessary to prevent emissions leakage.

New section 95852.1.1(a)(3) was added to specify that the biomass fuel must meet the requirements in sections 95852.1.1(a)(1) and (a)(2), and a verifier must be able to track the fuel back to a previous contract. This section is necessary to track where the fuel is coming from and to prevent double-counting of the fuel in case it is under another contract.

New section 95852.1.1(a)(4) specifies that once a certification program is in place, a fuel that meets the requirements of sections 95852.1.1(a)(1) and 95852.1.1(a)(2) will always be considered to have met the requirements in section 95852.1.

New section 95852.1.1(a)(5) specifies that if the biogas or biomethane is used at the site of production, and is not transferred to another operator (therefore not requiring a contract), then the operator must demonstrate that the fuel has been used or combusted in California prior to January 1, 2012. This section is necessary to make sure that the fuel was not previously used to produce useful energy transfer, or was being sent elsewhere and is now diverted to a capped entity, resulting in emissions leakage.

Section 95852.1.1(b) specifies that as part of a biomass-derived fuel's eligibility to avoid a compliance obligation, no party may sell, trade, give away, claim, or otherwise dispose of any of the carbon credits, carbon benefits, carbon emissions reductions, carbon offsets, or allowances, howsoever entitled, attributed to the fuel production that would prevent the resulting combustion from not having a compliance obligation. This section was necessary to specify that Generation of Renewable Energy Credits is allowable and will not prevent a biomass-derived fuel that meets this section's requirements from being exempt from a compliance obligation. However, to prevent double-counting of the environmental attributes of utilizing biomass derived fuel, the section prevents another source from claiming the benefits realized or using the benefits to fulfill a compliance obligation, or for any other purposes.

23. Emissions without a Compliance Obligation (Section 95852.2)

Section 95852.2(a) was modified to further clarify which types of waste sources do not have a compliance obligation. This modification did not exclude any sources that were included in the original regulation. Also in this section, staff deleted text that would not allow biogas from digesters to be exempt from a compliance obligation. This change was made based on staff's recommendation endorsed by the Board under Attachment B of draft Resolution 10-42.

New section 95852.2(a)(9) was added to specify that emissions from geothermal generating units and geothermal facilities do not hold a compliance obligation. Stakeholders submitted comment letters stating that emissions from geothermal facilities should not be classified as fugitive or process emissions, and should therefore not have a compliance obligation. Based on these comments, staff concluded that although geothermal facilities must report, they will not hold a compliance obligation. ARB will monitor their activities via the CEC renewable programs.

Sections 95852.2(a)(10) through (12) were included to clarify which source categories count toward the applicable reporting thresholds but do not count toward a covered entity's compliance obligation.

Section 95852.2(b) clarifies which fugitive and process emissions count toward a reporting threshold but do not count toward an entity's compliance obligation.

Sections 95852.2(b)(4) through (17) were included to align with the WCI Reporting Committee's revised list of "reporting only" emissions sources. This updates the sources listed in the Final Essential Requirements for Mandatory Reporting. Emissions data from these source types will be submitted for information only, and will not be subject to a compliance obligation.

Original sections 95852.2(d)(2)(A) through (F) have been removed. Based on stakeholder comments, staff determined that there are many conversion technologies that can be used to make a clean fuel from municipal solid waste, including anaerobic digestion. This language could be interpreted to apply these limitations to all forms of conversion, not just gasification. Original provisions 95852.2(d)(2)(E) and (F) have been removed as well so that the limitations imposed on gasification are not applied to all municipal solid waste conversion to clean burning fuel.

Various minor and non-substantive clarifications were also made to section 95852.2, to include the correct hierarchy in the numbering structure and consistency with the terminology used in the MRR for these sources.

24. Effect of Status Verification Statement on Calculation of Compliance Obligations (Section 95852.3)

This section was removed from the regulation because it is duplicative of language that exists in MRR section 95103.

25. Calculation of Covered Entity's Triennial Compliance Obligation (Section 95853)

Sections 95853(a), (b), (c), and (d) were modified to clarify that an entity's compliance obligation is calculated as the total of the emissions that received a positive or qualified positive emissions data verification statement, or were assigned by the Executive Officer. These revisions are necessary to clarify that when a reporting entity that holds a compliance obligation under the cap-and-trade regulation fails to submit an emissions data report or fails to obtain a positive or qualified positive emissions data verification statement by the applicable deadline, the Executive Officer will develop an assigned emissions level for the reporting entity, as specified in section 95131(c)(5)(A) through (C) of the MRR.

26. Quantitative Usage Limit on Designated Compliance Instruments—Including Offset Credits (Section 95854)

New section 95854(a) was originally expressed as part of the "O" term in the equation in this section and was moved into its own section to make it more clear which compliance instruments are subject to the quantitative use limit. This original text was also modified to include a reference to ARB offset credits (section 95820(b)), which was inadvertently omitted from the original regulatory text.

The text in new section 95854(b) now references section 95854(a), to make it clear which compliance instruments are subject to the quantitative usage limit. This text, as well as the modified text in the O_o and S terms of the equation, establishes that the quantitative usage limit applies to the triennial compliance obligation, not to the annual compliance obligation. This modification was made in response to stakeholder comments. Staff agrees with stakeholders, who have indicated that applying the limit to each annual surrender is overly complicated, and there is no benefit to the program when applying it annually.

Section 95854(c) was added to clarify that sector-based offset credits may only be used for up to 25 percent of the 8 percent total limit on designated compliance instruments, increasing to one-half of the 8 percent in the second compliance period. This reflects the intended changes identified for this section in Attachment B of Resolution 10-42.

27. Annual Compliance Obligation (Section 95855)

Section 95855 was modified to be consistent with section 95853 and the MRR.

28. Timely Surrender of Compliance Instruments by a Covered Entity (Section 95856)

Sections 95856(a) and (d) were modified to provide additional time for an entity to meet its annual surrender obligation. Changing the date to November 1 provides consistency between the annual surrender and triennial surrender. The extended deadline will also allow allocations to be distributed for the following year based on verified data.

Section 95856(e) was clarified to provide consistent terminology and process with the MRR. This section provides detail on what information will be needed to determine the triennial compliance obligation.

Minor and non-substantive clarifications were also made to section 95856, to add consistent terminology and correct cross-references within the regulation.

29. Untimely Surrender of Compliance Instruments by a Covered Entity (Section 95857)

Section 95857(b)(4) was modified to provide a covered entity time to acquire compliance instruments from an auction or reserve sale before being required to provide ARB the number of compliance instruments assessed for an untimely surrender. This change is necessary because several commenters were concerned that the originally proposed regulation did not allow enough time to acquire excess compliance instruments, and the immediacy of the surrender would create an unstable market. By extending the time for the untimely surrender obligation to be due after an auction and a reserve sale, ARB expands an entity's ability to comply with the excess emissions surrender obligation without resorting to the secondary market.

Section 95857(c) was rewritten to outline the consequence of not meeting the untimely surrender obligation. Section 95857(c)(1) indicates that ARB will determine the number of violations. Section 95857(c)(2) indicates the entity will have a new untimely surrender obligation that includes the original untimely surrender obligation that has not been satisfied. This new obligation is due immediately. These changes are necessary because a new time frame is created by the changes to 95857(b)(4), and additional rules regarding the calculation of the obligation are necessary in the event of a partial surrender. This section is necessary to inform all regulated parties of the consequences of missing the untimely surrender obligation deadline.

Section 95857(d) was modified to transfer three-fourths of the untimely surrender amount to the Auction Holding Account instead of to the Allowance Price Containment Reserve. This change was made in response to stakeholder concerns that putting the untimely surrender allowances in the Allowance Price Containment Reserve would tighten the allowance market for all participants.

Minor and non-substantive clarifications were also made to section 95857 to add consistent terminology and correct cross-references within the regulation.

30. Compliance Obligation for Under-Reporting in a Previous Compliance Period (New Section 95858)

New section 95858 was added to address cases when the Executive Officer finds there has been under-reporting by an entity after it has submitted compliance instruments to meet its compliance obligation. These provisions are necessary so that entities with a compliance obligation know what action the Executive Officer will take in the event they are found to have under-reported their emissions.

New section 95858(a) provides that entities that are found to have under-reported their emissions by less than five percent must not take any further action to replace the deficient compliance instruments. This corresponds with the requirements of the MRR.

New section 95858(b) provides that entities that are found to have under-reported their emissions by more than five percent must surrender compliance instruments in the amount calculated pursuant to the formula in this section. This amount equals the amount of emissions determined by the Executive Officer minus the reported and verified emissions and minus five percent of the reported and verified emissions. The reported and verified emissions are multiplied by five percent and subtracted out because the MRR allows for an understatement of up to five percent in reporting. Requiring entities that under-report emissions to surrender compliance instruments equal to 105 percent of the under-reported emissions, ensures the environmental integrity of the program.

New section 95858(c) was added to provide entities required to turn in compliance instruments for under-reported emissions a six-month period to submit them to ARB. Staff included a six-month period to give covered entities enough time to acquire sufficient compliance instruments and avoid any short-term shocks to the market. This section also specifies which compliance instruments may be used to meet this requirement and provides that if the entity turns in all of the compliance instruments within the six-month period they are not subject to the excess emissions obligation under section 95857. If the entity turns them in within the six months, ARB considers the submittal to be a timely surrender.

31. Disposition of Allowances (Section 95870)

Section 95870(a) was modified to change the date of creation of the Allowance Price Containment Reserve to July 18, 2012, to accommodate the change in the auction schedule in 2012. Since no allowances will be issued for 2012, the reserve will be filled only with allowances issued from 2013 through 2020. Section 95870(b) was modified to change the date at which the Executive Officer would transfer future vintage allowances to the Auction Holding Account. Both changes are necessary to reflect the change in dates of the first auction and reserve sales.

Section 95870(b) also was modified to increase the amount of future vintage allowances auctioned each year from two percent to 10 percent of future allowance budgets. This change is required to respond to stakeholder concerns about preparing for the second compliance period, when the program size increases due to the addition of the transportation fuels and upstream natural gas sectors. The increase in the advance auction will allow covered entities to accumulate allowances for the second compliance period while diminishing the need to bank allowances from the first compliance period, which might otherwise tighten the first compliance period's market more than is optimal.

New section 95870(c), was added to include new language as directed in Resolution 10-42 to specify how many allowances will be set aside for Voluntary Renewable Electricity reductions. Section 95870(e), which was originally reserved as a placeholder for the allocation to voluntary renewable energy allowance set aside was deleted.

Original section 95870(c), now section 95870(d), was modified to reflect an increased number of allowances available for allocation to electrical distribution utilities. Additionally, Table 8-1 has been updated to clarify the relationship between activities that produce products at risk for leakage and the sectors in which these activities occur.

32. General Provisions for Direct Allocations (Section 95890)

Section 95890 was modified to better clarify how verification impacts eligibility for free allocation.

33. Allocation for Industry Assistance (Section 95891)

In section 95891(b), the formula was modified to change the timing of output data, in response to stakeholder concerns about prolonged exposure to recessionary output levels. A "true-up" term was added to the equation to ensure that the amount of allocation received for a given year is corrected to actual production for that year. The assistance factor (determined by leakage risk) and the cap decline factor were clarified to be a function of activity rather than of sector.

The product benchmarks for industrial activities, as presented in Table 9-1 of section 95891(b), were added per Resolution 10-42, to allow allowances to be allocated under the product-based approach. The product outputs used to establish the product benchmarks were altered from the proposal outlined in staff's Initial Statement of Reasons (ISOR) as necessary.

The name of the "thermal energy based allocation calculation methodology" in section 95891(c) was renamed the "energy-based allocation calculation methodology" to more explicitly recognize the impact of electrical energy carbon costs and cost recovery. A new term was derived from a heat rate based on the pending Public Utilities Commission Qualified Facility settlement to quantify the expected carbon cost recovery in the price of power sold from an industrial facility. Equivalent adjustments were made when establishing the values of the product-based benchmarks. The formula was also altered to show how allocations to any combined heat and power facilities will receive allowances under this approach.

In section 95891(c)(1), text was added to explain that under the energy-based approach, the baseline annual amount of California GHG allowances directly allocated to each eligible entity will be representative of current activity but provide appropriate credit for early voluntary reductions in GHG emissions. The descriptions of data sources that ARB will use to allocate under this methodology were clarified, and it was explained that, if necessary, the Executive Officer will solicit additional data to establish a representative baseline allocation. This change is necessary to ensure that covered entities clearly understand how the allowances are allocated among eligible entities.

The cap decline factor table (Table 9-2) in section 95891(c) was altered slightly to show that this factor impacts the allocation to electrical distribution utilities, as well as to industrial facilities, and to remove the year 2012 to accommodate the change in compliance obligation start date.

34. Allocation to Electrical Distribution Utilities for Protection of Electricity Ratepayers (Section 95892)

This section was modified to show how many allowances each electrical distribution utility will receive as a portion of the total electricity sector allocation created in section 95870. This allocation to each utility is presented in Table 9-3 of section 95892(f). Appendix A explains how these values were derived.

Additionally, Table 9-3 was added to include the specific percentage allocation of allowances to individual electrical distribution utilities.

Section 95892(a) was added to explicitly state ARB's intent that allowances allocated to electrical distribution utilities be used for ratepayer benefit, and any proceeds from the sale of allowances be similarly used for ultimate ratepayer benefit.

Section 95892(c) was modified to delete the existing requirement that electrical distribution utilities offer all allowances in their limited use holding accounts to auction within the year they were received. New section 95892(c)(1) requires that one-sixth of all 2013 vintage allowances in limited use holding accounts must be consigned to auction in each of the two auctions scheduled for 2012. Section 95892(c)(2) recreates the existing consignment requirement for auctions taking place in calendar years after 2012. These changes were needed to accommodate the decision to have two auctions of vintage 2013 allowances in 2012 before the beginning of the first compliance period in 2013.

As detailed in footnote 22 of the ISOR for the cap-and-trade regulation, some generators and industrial steam producers have reported that some existing contracts do not include provisions that would allow full pass-through of carbon costs associated with cap-and-trade. Staff is evaluating this issue to determine whether some specific contracts may require special treatment on a case-by-case basis. In several cases, staff is aware and encouraged that parties are in the process of, or already have, negotiated new contracts to resolve this issue. Staff believes that bilateral contract negotiations would provide the best resolution of this issue. Should contract renegotiation not be possible in all cases, staff will continue discussions with counter-parties to consider how this issue should be resolved in the regulation.

Section 95892(d) requires auction proceeds from consigned allowances to be used only for ratepayer relief. Some stakeholders have expressed concerns with these provisions. Staff is requesting comments on these provisions.

Section 95892(e) was modified to require reporting of the use of allowance value to ARB. These changes are necessary to ensure that allowance value is being used for ratepayer benefit, consistent with ARB's stated policy.

Section 95892(f) was added to clarify that any use outside of ratepayer benefit of allowance value is prohibited under this regulation. This section is necessary to ensure that all entities subject to the regulation are aware of the limited use of allowance value pursuant to this regulation.

35. Reserved for Allocation to Natural Gas Distribution Utilities for Protection of Natural Gas Ratepayers (Section 95893)

No modifications were made to section 95893.

36. Auction of California GHG Allowances (Section 95910)

Section 95910(a) was modified to match the new schedule of auctions and reserve sales. This was necessary to accommodate covered entities' verification deadlines in the MRR and the decision to have two auctions in 2012 and four from 2013 forward.

Section 95910(c)(1) modifies an existing provision that one-fourth of the allowances allocated for auction each year will be sold at each auction, to reflect the decision to begin such auctions in 2013.

Section 95910(c)(2) was modified to have the existing requirements for the advance auction begin in 2013, not 2012. One-half of the 2015 vintage allowances allocated to the advance auction will be sold at each of the two auctions taking place in 2012. This clarification is necessary because the forward auction for the 2015 vintages will be provided over two auctions, in contrast to the forward auction of 2016 vintage allowances, which will be provided over four auctions.

Section 95910(d)(4) was modified to reflect the change in the auction schedule. For auctions beginning in 2013, the allowances must now be consigned to the auction at least 75 days prior to the auction. The modified provisions require that for the two auctions in 2012, the consignments need occur only 10 days before the auction, because the number of allowances to be consigned is set in the regulation and will be known in time to be included in the auction notice.

37. Format for Auction of California GHG Allowances (Section 95911)

Section 95911(b)(4)(A) was added to clarify that unsold, non-consigned allowances at auction will be allocated equally to the three tiers of the Allowance Price Containment Reserve. Any allowances remaining after this division will be deposited in the lowest-priced tier. Section 95911(b)(4)(B) was added to clarify that unsold future vintage allowances will be returned to the Auction Holding Account for sale at the next auction.

Section 95911(b)(6) modifies the effective dates of the reserve price and the reserve price escalator to reflect the new schedule for auctions. The reserve price for the sale of vintage 2015 allowances in 2012 was changed to reflect the value of the reserve price that would prevail in 2015.

Original section 95911(c) was deleted to remove a reference to provisions on disclosable bidding associations. ARB removed the existing provisions for disclosable bidding associations after changes to corporate associations and beneficial holding rules rendered the bidding association provisions unnecessary.

New section 95911(c) was reorganized for clarity, and in particular that the original text does not apply to the advance auction. The purchase limit for the advance auction will be 25 percent. A higher purchase limit was chosen for the advance auction because staff concluded that there is a lower risk of market manipulation after the advance auction compared with the current vintage auction, due to the lower proportion of each year's allowance budget sold at the advance auction and because future vintage allowances cannot be used for current compliance.

38. Auction Administration and Registration (Section 95912)

New section 95912(a)(2) was added to allow the Executive Officer to designate a financial services administrator to execute the financial transactions required for the market program's implementation. These changes were necessary because it is highly probable that the Executive Officer will contract for these services. Clarifications were also made regarding the confidentiality of auction-related data in new section 95912(f).

Several new provisions were added, on the maintenance of auction registration (new section 95912(d)), restriction on communicating confidential information (new section 95912(e)), and the protection of confidential information by the Executive Officer (new section 95912(f)). Original section 95912(e) on the provision of false information was moved to section 95914(c), along with other provisions regarding auction participation and prohibited behavior, because it was more contextually appropriate to include those provisions in the requirements for auction participation.

39. Sale of Allowances from the Allowance Price Containment Reserve (Section 95913)

Section 95913 was modified to provide clarification on the sale of allowances from the allowance price containment reserve.

Section 95913(a) was modified to clarify that a financial services administrator will conduct the financial transactions for sales from the Allowance Price Containment Reserve Account. This is necessary to make clear that ARB will not actually be conducting financial transactions, and that they will occur only through a third party.

Section 95913(c) was modified to clarify that only covered entities that are registered with the cap-and-trade program shall be eligible to purchase allowances from the Allowance Price Containment Reserve Account. This clarification and limitation is necessary because the purpose of the Allowance Price Containment Reserve Account is to protect covered entities from the possibility of allowances being unavailable. If all registered participants were able to purchase from the Allowance Price Containment Reserve Account, the policy of ensuring that allowances are available would be substantially undermined.

Staff made two changes to accommodate the change in start date for the compliance obligation in the cap-and-trade program. In section 95913(c)(3)(A) the date of the first reserve sale was changed from 2012 to 2013. In sections 95913(d)(2) and (3) staff changed the effective dates for setting the prices in each tier, as well as the price escalation mechanism, to reflect the new compliance obligation start date.

Section 95913(e)(2) was modified to include the role of a financial services administrator in the processing of the bid guarantee.

To address stakeholder concerns, section 95913(f)(3) was modified to implement a new process for determining the number of allowances purchased from the Allowance Price Containment Reserve. This change was made in response to stakeholder comments that the original bid process in original section 95913(e)(1) was unnecessarily cumbersome, and together with the tie-breaking procedure could result in bidders paying too much for, or not getting, the allowances they need. Some stakeholders recommended that ARB replace bidding on specific tiers of the reserve with a process in which bidders specify a quantity and a maximum price, and the bids are filled with the lowest-priced allowances available. ARB requests comment on whether this process represents a simplification and reduces uncertainty.

Various other minor and non-substantive clarifications were also made to section 95913.

40. Disclosure of Direct and Indirect Corporate Associations (Section 95914)

Section 95914 was renamed Auction Participation and Limitations and modified to move original text regarding disclosable corporate associations to new section 95833 in subarticle 5. Text regarding the application of corporate associations to the holding limit was also moved to section 95920. Text was also added to clarify how the corporate and bidding association rules are applied to the purchase limit at auction. Text relating to provision of false information and protection of confidential information was moved from section 95912(e) to section 95914(c). These changes were necessary to place the language in the appropriate context within the regulation.

41. Identifying Disclosable Bidding Associations (Section 95915)

Section 95915 has been deleted. The expanded requirements on corporate associations in new section 95833, and beneficial holdings in new section 95834, have made the existing requirements on disclosable bidding associations unnecessary. Parts of section 95915(e) were also moved to section 95914.

42. Trading (Section 95920)

Original section 95920(a) on general prohibitions on trading was moved to section 95921. Text on the holding limit (originally in section 95920(b)) was significantly rewritten for clarity and several new subsections added. New section 95921(a) reference the definition of corporate association to new section 95833.

New section 95921(b) adds new provisions explaining that the holding limit does not apply to allowances contained in a limited use holding account. In addition, allowances held by a clearing entity will be counted against the holdings of the entity to whose account the instruments will be transferred when the transaction has been cleared. The section adds a requirement that if a transaction is discovered to violate the holding limit after the transaction has been discovered, then the transaction may be reversed and a penalty applied.

New section 95920(c) was added to clarify that the holding limit will be applied separately to allowances which can be used for current compliance and to allowances from future vintages that cannot be used for current compliance.

New section 95920(d)(1) contains the existing holding limit formula to be applied to allowances that can be used for current compliance. New section 95920(d)(2) contains an extensive clarification of the calculation of the existing limited exemption from the holding limit in section 95920(d)(1). Stakeholders had commented that the language did not convey that the exemption was cumulative through the compliance period, nor was it clear how the exemption would be calculated based on emissions reports.

New section 95920(e) contains a formula for calculating the holding limit for future vintage allowances that cannot be used for current compliance. The formula is similar to the one in section 95920(d)(1), except that the “base” parameter was multiplied by three and the formula is calculated using the entire compliance period budget rather than a single budget year.

43. Conduct of Trade (Section 95921)

Section 95921(a) was rewritten to address the handling of violations that are detected before the transaction is registered, as well as those that are detected after the transaction is registered. Specifically, the section now addresses the consequences of violating the requirements of subarticle 11 at two possible times: if the violation is discovered before the transaction is recorded (section 95921(a)(1)(A)) and if the violation is discovered after the transaction is recorded (section 95921(a)(1)(B)). These clarifications were necessary to inform covered entities and participants in the cap-and-trade program of the consequences of violating the various restrictions in subarticle 11. New section 95921(a)(2) was added to clarify that the account numbers to be used in transactions between registered entities are those of holding accounts.

A new section 95921(b)(3) was added to make explicit that violations of subarticle 11 also subject participants in the cap-and-trade program to penalties pursuant to section 96013. This addition is necessary to make explicit the scope of the penalties available to ARB in the event of a violation of the restrictions of subarticle 11, and to make clear that the specific actions of sections 95921(a)(1) and (a)(2) are not exclusive.

New section 95921(d) was added to provide provisions on the protection of confidential market information. New sections 95921(e) and (f) were added to move existing provisions in other sections to this section, with some clarifications.

44. Banking, Expiration, and Voluntary Retirement (Section 95922)

No modifications were made to section 95922.

45. General Requirements (Section 95940)

No modifications were made to section 95940.

46. Procedures for Approval of External GHG ETS (Section 95941)

No modifications were made to section 95941.

47. Approval of Compliance Instruments from External GHG ETS (Section 95942)

No modifications were made to section 95942.

48. Reserved for Linkage (Section 95943)

No modifications were made to section 95943.

49. General Requirements for ARB Offset Credits (Section 95970)

Section 95970 was modified to distinguish between an ARB offset credit and a registry offset credit, and to establish the requirements that each must meet. These clarifications were necessary because the originally proposed language could have been interpreted to mean that any offset credit could be used in the cap-and-trade program, without limiting them to ARB-issued offset credits.

Various minor and non-substantive clarifications were also made to section 95970.

50. Procedures for Approval of Compliance Offset Protocols (Section 95971)

No modifications were made to section 95971.

51. Requirements for Compliance Offset Protocols (Section 95972)

Section 95972(c) was added to require that all Compliance Offset Protocols must specify the geographic location where they are applicable. This requirement clarifies that compliance offset protocols can only be applicable in North America. This change was necessary because stakeholders were confused about the possible location of the offset projects for which ARB would issue ARB offset credits.

Section 95972(a) was also modified to require that Compliance Offset Protocols include standardized methods. As discussed in the ISOR, this ensures a consistent implementation of all offset projects within a project type.

52. Requirements for Offset Projects Using ARB Compliance Offset Protocols (Section 95973)

Section 95973 was modified to address stakeholder comments by clarifying the eligibility criteria for offset projects. The text was also modified to address requirements that unintentionally would prohibit early action offset projects from being able to transition to Compliance Offset Protocols based on the offset project commencement date. A new section 95973(c) now makes it clear that early action offset projects may have commencement dates prior to December 31, 2006, which is consistent with the requirements in section 95990.

Section 95973(d) was added to clarify that offset projects developed on lands related to federally recognized Indian Tribes are eligible only if the Offset Project Operator or Authorized Project Designee demonstrates the existence of a limited waiver of sovereign immunity between the Tribe and ARB, entered into pursuant to section 95975 of this article. This modification also clarifies the categories of lands to which this requirement applies. This new provision is needed to ensure Offset Project Operators or Authorized Project Designees meet the requirements for listing in section 95975.

Various minor and non-substantive clarifications and updates were also made to section 95973.

53. Authorized Project Designee (Section 95974)

Section 95974 was modified to clarify when an Offset Project Operator may identify an Authorized Project Designee in response to stakeholder comments, and to correct and add several cross-references within the regulation.

54. Listing of Offset Projects Using ARB Compliance Offset Protocols (Section 95975)

Section 95975(a)(3) was deleted and moved to section 95975(b) to place the language in the appropriate context within section 95975.

Language was added to section 95975(c)(2) to specify that all Offset Project Operators or Authorized Project Designees specifically submit to California's jurisdiction to resolve any disputes regarding enforcement of the regulation against the Offset Project Operator or Authorized Project Designee. This change is necessary to make clear to Offset Project Operators or Authorized Project Designees that by participating in California's cap-and-trade program in this capacity, they will be subject to California's jurisdiction, regardless of the offset project's physical location.

New section 95975(c)(3) was added to include additional attestations that must be made when an offset project is listed. Original section 95975(c)(4) was deleted and moved to section 95975(d) to place the language in the appropriate context within section 95975.

New section 95975(c)(5) requires that an Offset Project Operator or Authorized Project Designee disclose any offset credits issued for the same project for any other purposes in any other program. This is to address stakeholder concerns regarding any double-counting of the GHG reductions or GHG removal enhancements in multiple programs.

New section 95975(l) was added to clarify that a Tribe, in addition to meeting the other offset project listing requirements, must also enter into a limited waiver of sovereign immunity with ARB related to the Tribe's participation in the cap-and-trade program prior to the listing of any offset project being developed on lands related to the Tribe, as specified in section 95973(d). This ensures ARB's ability to pursue judicial remedies, if necessary, regarding these offset projects when enforcing the requirements of the Compliance Offset Protocols and the cap-and-trade regulation.

Various minor and non-substantive clarifications were also made to section 95975 to ensure consistency in terminology and references throughout the regulation.

55. Monitoring, Reporting, and Record Retention Requirements for Offset Projects (Section 95976)

Section 95976(d) was modified to address stakeholder concerns about a calendar year reporting period with a fixed annual "verification period." To address these stakeholder concerns, the new requirements cover a reporting period that is not tied to the calendar year.

The record retention requirements in section 95976(e)(2) were changed to 15 years following the issuance of ARB offset credits due to stakeholder concerns about an unnecessarily long record retention requirement for forestry projects.

Various minor and non-substantive clarifications were also made to section 95976.

56. Verification of GHG Emission Reductions for GHG Removal Enhancements from Offset Projects (Section 95977)

Section 95977(e) was moved to a new section 95977.1 in response to stakeholder comments that the references in original section 95977 throughout the regulation were very lengthy and hard to follow. Additional modifications were made to the timing for the verification schedule (sections 95977(b) and (c)) and the submittal of Offset Verification Statements (section 95977(d)), to be consistent with the new offset reporting schedule in section 95976(d) and to clarify the verification cycle.

Various minor and non-substantive clarifications were also made to section 95977 to ensure consistency in terminology throughout the regulation.

57. Requirements for Offset Verification Services (New Section 95977.1)

New section 95977.1 was added in response to stakeholder comments that the references in the original section 95977 to other sections throughout the regulation were very lengthy and hard to follow.

Original section 95977(e)(1), now new section 95977.1(a) dealing with rotation of verification bodies, was modified to clarify that the rotation of verification bodies must occur on an offset project basis. The intent of the language was not changed. These clarifications were made in response to stakeholder comments that it was unclear if the rotation of verification bodies every six years applied at the individual offset project level or Offset Project Operator level.

Original section 95977(e)(2)(C)(iv), now new section 95977.1(b)(3)(D) dealing with site visits for offset projects, was modified to allow site visits to be conducted at least once every six years for those forest offset projects approved for less-intensive verification. These changes were made in response to stakeholder comments that annual site-visit verifications for forest projects are cost-prohibitive and unnecessary. Staff agrees that as long as on-site verification is conducted at least once every six years, there is reasonable assurance.

A new requirement was added to original section 95977(e)(2)(C)(iv)(a.), now new section 95977.1(b)(3)(D)(1.) that requires the offset verification team to review the listing information submitted by the Offset Project Operator or Authorized Project Designee. This requirement is needed to ensure the offset verification team is satisfied that all of the correct documentation was submitted by the Offset Project Operator or Authorized Project Designee.

Original section 95977(e)(2)(C)(xvii), now new section 95977.1(b)(3)(Q), was modified to change the term “errors” to “discrepancies” in the formula for calculating offset material misstatement. This change was necessary because the definition of offset material misstatement uses the term “errors” twice with two different meanings, and the terminology for the calculation of offset material misstatement in this provision needs to be consistent with the revised definition.

Original section 95977(e)(2)(C)(xviii)(d)(i), now new section 95977.1(b)(3)(R)(4.)(a.), was modified to require that a verification body must submit verification reports to Offset Project Registries with the Offset Verification Statement. This provision is necessary to ensure that the Offset Project Registries possess all pertinent information regarding the offset project.

Original section 95977(e)(2)(C)(xviii)(d)(iii), now new section 95977.1(b)(3)(R)(4.)(c.), was modified to disallow the use of Qualified Positive Offset Verification Statements for certain project types, if specified in the Compliance Offset Protocol. The revisions to Compliance Offset Protocol U.S. Forest Projects disallows the use of Qualified Positive Offset Verification Statements because, for forest projects, ARB must ensure that all protocol requirements are met, including sustainable harvesting requirements.

Original sections 95977(e)(2)(C)(xix)(a.) through (c.) were modified and/or deleted and replaced with new sections 95977.1(b)(3)(R)(5.) through (7.). These changes reflect the deletion of Offset Project Registries from the appeals process for Adverse Verification statements. This was clarified to be consistent with the MRR, and it reflects stakeholder comments that the appeals process should only be limited to determinations made by the Executive Officer of ARB and that ARB should be the only one to make these determinations.

Various minor and non-substantive clarifications were also made to the original section 95977(e) which is now part of section 95977.1. These include general clarifications to ensure consistency of terminology and correct section references within the regulation.

58. Additional Project-Specific Requirements for Offset Verification Services (New Section 95977.2)

New section 95977.2 was added to replace the original section 95977(f) in response to stakeholder comments that the references in the original section 95977 to other sections throughout the regulation were very lengthy and hard to follow. No substantive changes were made to the actual text.

59. Offset Verifier and Verification Body Accreditation (Section 95978)

Various minor and non-substantive changes were made to section 95978 for consistency in terminology within the regulation.

60. Conflict-of-Interest Requirements for Verification Bodies for Verification of Offset Project Date Reports (Section 95979)

Section 95979 was modified to include new Board-directed text in Resolution 10-42 that clarifies the conflict-of-interest requirements as they pertain to air districts. Changes were also made to include personal or family relationships as a medium for potential for conflict of interest to strengthen the conflict-of-interest requirements between verifiers and Offset Project Operators and Authorized Project Designees. This is also consistent with the MRR.

Various minor and non-substantive clarifications were also made to section 95979 for consistency in terminology within the regulation.

61. Issuance of Registry Offset Credits (Section 95980)

The process for issuance of registry offset credits and ARB offset credits was clarified by revising sections 95980 and 95981 and adding new section 95980.1 and 95981.1. Sections 95980 and 95980.1 apply specifically to the issuance of registry offset credits; sections 95981 and 95981.1 apply specifically to the issuance of ARB offset credits.

Section 95980 was modified to apply only to the issuance registry offset credits issued by an Offset Project Registry. Registry offset credits are not allowed to be used for compliance in the program, because only compliance instruments issued by ARB or an approved program for linkage may be used for compliance.

Various minor and non-substantive clarifications were also made to section 95980 to ensure consistency of terminology and correct section references within the regulation.

62. Process for Issuance of Registry Offset Credits (New Section 95980.1)

New section 95980.1 was added to clarify the process by which a registry would issue registry offset credits. The processes for issuing both registry and ARB offset credits were originally in section 95981. This new section and new section 95981.1 were added to establish the difference between the processes for issuing a registry offset credit and those for issuing an ARB offset credit, and to provide clarity.

63. Issuance of ARB Offset Credits (Section 95981)

Section 95981 was modified to apply only to the issuance of ARB offset credits. ARB offset credits can only be issued by ARB because they are able to be used for compliance. The issuance of both ARB offset credits and registry offset credits were originally in section 95980. This modified section and modified section 95980 clarify the difference between the issuance of ARB offset credits and registry offset credits. In addition, new attestations that must be made by Offset Project Operators and Authorized Project Designees were added to the process for issuing ARB offset credits (new section 95981(c)). This will help to ensure that all program requirements are met before ARB offset credits are issued. To ensure that stakeholders are not confused, and for ease of review, the previous section 95981 is shown in complete strikeout, and new section 95981 is underlined.

64. Process for Issuance of ARB Offset Credits (New Section 95981.1)

New section 95981.1 was added to clarify the process by which ARB would issue ARB offset credits. The processes for issuing both registry and ARB offset credits were originally in section 95981. This new section and new section 95980.1 were added to establish the difference between the processes for issuing a registry offset credit and an ARB offset credit, and to provide clarity. Only ARB can issue compliance instruments, including ARB offset credits that can be used for compliance. ARB offset credits are issued by ARB once ARB receives all attestations required by offset project developers, authorized project designees, and verification bodies. This section also clarifies that ARB will make the final determination on whether or not a registry offset credit meets the requirements to meet all requirements of the regulation.

65. Registration of ARB Offset Credits (Section 95982)

Section 95982 was modified to include minor and non-substantive clarifications, and to improve consistency in terminology.

66. Forestry Offset Reversals (Section 95983)

Section 95983(a) was modified to delete text that was duplicative of text in section 95983(a)(3). Text in section 95983(a)(3) was revised for clarity, without changing the intent.

The timing for Offset Project Operators or Authorized Project Designees to notify ARB of an intentional reversal was changed in section 95983(b) from six months to 30 days. Staff believes that since the notification is based on the discovery of the reversal, as opposed to its occurrence, that 30 days is sufficient for notification. Section 95983(b)(1)(A) was moved to section 95983(b), and section 95983(b)(1)(B) was moved to section 95983(b)(1), to provide clarity without changing the original text's intent. Section 95983(b)(2) was modified to clarify how ARB offset credits are retired from the Forest Buffer Account in the event of an unintentional reversal and to remove an inaccurate citation.

Sections 95983(c)(1) and original section 95983(c)(2) were modified and/or deleted to clarify the process for notifying ARB of an intentional reversal. ARB will not notify the Offset Project Operator or Authorized Project Designee of its determination because the occurrence of an intentional reversal is required to be verified in new section 95983(c)(2) within one year of the occurrence of an intentional reversal. This verification will determine if there is an intentional reversal.

New section 95983(c)(3) replaces original section 95985(e), which requires that Offset Project Operators or Authorized Project Designees replace ARB offset credits with valid compliance instruments in the case of an intentional reversal. The original replacement timing was 30 days, and staff changed it to 90 days to give entities enough time to acquire allowances at auction or purchase additional ARB offset credits in the market. A new requirement was added to section 95983(c) that states that ARB offset credits will be retired from the Forest Buffer Account if the reversed tons are not replaced by the Offset Project Operators or Authorized Project Designees within the 90 days. This ensures that the system is made whole and that the environmental integrity of the program is intact. If the Offset Project Operator or Authorized Project Designee does not replace the ARB offsets within the 90 days, and ARB offset credits are retired from the Forest Buffer Account, ARB will assess penalties pursuant to section 96014. This allows the program to be made whole and still requires that the “bad actors” are appropriately penalized for not making the program whole.

New section 95983(c)(4) was added to clarify what happens in the case of an early forest project termination. These provisions were added to deter forest project owners from terminating their offset projects early, given permanence requirements that require the sequestration of carbon for 100 years. If there is an early project termination, ARB will retire ARB offset credits from the Forest Buffer Account and notify the Offset Project Operator or Authorized Project Designee of the retirement. This ensures that the system is made whole and that the environmental integrity of the program is intact. The Offset Project Operator or Authorized Project Designee must replace all of the reversed tons calculated pursuant to Compliance Offset Protocol U.S. Forest Projects to ARB within 90 calendar days. If the Offset Project Operator or Authorized Project Designee does not replace the ARB offsets within the 90 days, and ARB offset credits are retired from the Forest Buffer Account, ARB will assess penalties pursuant to section 96014. This allows the program to be made whole and still requires that the “bad actors” are appropriately penalized for not meeting the requirements of this article and not making the program whole.

Sections 95983(d) and (e) were modified and deleted respectively, to combine the requirements for the disposition of forest offset projects in one section dealing with all reversals. This change was made because there was no need to have two sections. New section 95983(d)(3) was added to replace the text in original section 95983(e)(2), which was deleted for reasons stated above.

Various minor and non-substantive clarifications were also made to section 95983 to provide consistency in terminology and correct references within the regulation.

67. Ownership and Transferability of ARB Offset Credits (Section 95984)

Section 95984 was modified to specify for which purposes an ARB offset credit can be used. These changes were needed to make it clear to market participants how an ARB offset credit can be used within the cap-and-trade program. Additionally, a numbering structure was added to this section for readability.

Various minor and non-substantive clarifications were also made to section 95984.

68. Invalidation of ARB Offset Credits (Section 95985)

Section 95985(a)(2) was deleted and moved to section 95985(a). Section 95985(a)(1) was deleted because it was mistakenly included in the original regulation. All offsets will be retired once they are used for compliance, therefore we cannot require that all retired offsets be invalidated.

Section 95985(b) was modified in response to stakeholder comments to include a statute of limitations within which ARB would be able to invalidate an ARB offset credit. Staff determined that an eight-year time limit was sufficient to allow two verification bodies to review all the related offset project documentation, since verification bodies must be rotated once every six years. This gives ARB sufficient time to review all verification-related material.

Original section 95985(b)(1) was deleted because the reversals and replacement of forest-related offsets is being handled in section 95983. Original section 95985(b)(2), now section 95985(b)(1), and new sections 95985(b)(2) through (b)(4), clarify the conditions under which ARB would invalidate an ARB offset credit. These changes respond to stakeholder concerns that they could not quantify the invalidation risk because the conditions were too broad.

In addition, staff added new sections 95985(b)(5) and (6) to include a couple of exceptions to the eight-year limit under which invalidation would have a five-year time limit. The exceptions encourage a quicker verifier rotation so that any issues that may occur may be uncovered sooner, further enhancing the integrity of the offset program.

Original section 95985(c) was deleted and moved to new section 95985(e) to provide the correct sequencing in this section due to the inclusion of new sections 95985(c) and (d). New section 95985(c) was pulled out of original sections 95985(d) and (e) and identifies the current holder or retiree of the ARB offset credits in question. This was added because this party is referenced several times in this section and allows staff to reference this section, as opposed to writing it out in each provision. New section 95985(d) provides a dispute resolution process to allow entities to submit additional information to ARB before a final determination is made for invalidation. These provisions were added in response to stakeholder comments that there should be a notification and due process associated with invalidations.

As mentioned above, new section 95985(e) was moved from original section 95985(c). These provisions are generally the same except that new section 95985(e)(2) was added to allow for the dispute resolution process mentioned above.

Original section 95985(d), now section 95985(f), was modified to change the replacement timing from 30 days to 90 days, to give entities enough time to acquire allowances at auction or purchase additional ARB offset credits in the market.

Original section 95985(e), now section 95985(g), was modified to clarify that the forest owner is responsible to replace any ARB offset credits that are invalidated due to violations of 95985(b). Original section 95985(f) was deleted because it duplicated requirements in section 95983(a) and because replacements of ARB offsets due to forest sector reversals are now all handled in section 95983.

New section 95985(h) was added to explicitly state that ARB maintains its enforcement authority for any violations under this article, even in the event of an invalidation.

Various minor and non-substantive clarifications were also made to section 95985 to provide consistent terminology and section references within the regulation.

69. Executive Officer Approval Requirements for Offset Project Registries (Section 95986)

Section 95986(c) was modified to remove the requirement that an Offset Project Registry apply for a holding account. This provision was mistakenly included in the original regulation and conflicts with section 95814, which states that Offset Project Registries may not hold compliance instruments.

Section 95986(c)(1)(E) was modified to change the amount of professional liability insurance that Offset Project Registries must maintain from fifty million dollars to five million dollars. This change reflects stakeholder comments that the dollar amount was too high and that insurance was not offered at that level of coverage. Sections 95986(c)(2)(A)(1.) and (2.) were modified to specify what type of conflict-of-interest policies Offset Project Registries must have. These changes were made to clarify the types of policies that are acceptable by ARB.

New section 95986(c)(2)(F) was added to clarify how the Offset Project Registry application process applies to large organizations that may have a dedicated subdivision that wants to provide registry services. This is in response to stakeholder comments that potential Offset Project Registries could be part of a larger organizational structure, and that the original language could preclude them from meeting application requirements.

Section 95986(c)(3)(C) was modified to remove the requirements that Offset Project Registries track prices and counter parties. These were removed in response to stakeholder comments that Offset Project Registries do not have the capability to track them.

Section 95986(d)(1) was modified to make it clear that Offset Project Registries cannot be Offset Project Operators or Authorized Project Designees for those offset projects developed under Compliance Offset Protocols. This change was made in response to comments that Offset Project Registries should be able to act in this capacity for those projects that are voluntary and that will not come in to the compliance offset program.

New section 95986(d)(3) was added to be consistent with the new text added in section 95986(c)(2)(F).

The changes to section 95986(h) and the addition of new section 95986(i) clarify the level of expertise and training that Offset Project Registries and their staff must have to be approved, including an examination process. These changes were necessary to clarify the requirements for stakeholders who plan to apply to be an approved Offset Project Registry.

The Offset Project Registry approval process was also strengthened to require that their staff take training and demonstrate knowledge about ARB Compliance Offset Protocols and regulatory requirements.

Original section 95986(j), now section 95986(k), was modified to clarify what happens to offset projects that reside at an Offset Project Registry, whose approval has been suspended or revoked. These offset projects may transfer to another approved registry and continue its current crediting period. This change was necessary because stakeholders were concerned that their offset projects could be ineligible if an Offset Project Registry's approval was suspended or revoked.

Various minor and non-substantive clarifications were also made to section 95986 to provide consistent terminology and section references within the regulation.

70. Offset Project Registry Requirements (Section 95987)

Section 95987(a) was modified to clarify that Offset Project Registries can also list offset projects not developed using Compliance Offset Protocols. Offset projects developed under a manner other than by using the Compliance Offset Protocols would not be eligible to be issued ARB offset credits, and the Offset Project Registry must make it clear that these offset projects do not qualify for compliance. This change was made in response to comments that Offset Project Registries should be able to act in a registry capacity for those projects that are voluntary and that will not come in to the compliance offset program.

Section 95987(c) was modified to add a timing component of 15 days for an Offset Project Registry to submit any new conflict-of-interest documentation to ARB once it receives it from an Offset Project Operator and Authorized Project Designee. This text was added because it was unintentionally omitted from the original regulation.

Section 95987(e) was modified to change the number of in-person audits that Offset Project Registries must perform from 20 percent to 10 percent. Staff reduced the number of in-person audits because ARB will also have an audit program that will include in-person audits, in addition to those performed by Offset Project Registries. ARB will also have access to the audit results collected by Offset Project Registries.

Section 95987(f) was added to require Offset Project Registries to review each verification report before accepting a verification opinion for an offset project listed using a Compliance Offset Protocol. This text was added to provide greater assurance to ARB and Offset Project Registries that the verification opinions are accurate.

New section 95987(k) was added to explain that any insurance mechanisms developed by an Offset Project Registry are not required to be purchased or used by any parties involved in ARB offset credit transactions, thus ensuring that other private entities may develop insurance mechanisms.

Various minor and non-substantive clarifications were also made to section 95987 to provide consistent terminology and section references within the regulation.

71. Record Retention Requirements for Offset Project Registries (Section 95988)

Section 95988 was modified to change record retention requirements for Offset Project Registries to 15 years. This change was made to be consistent with the new record retention requirements for Offset Project Operators and Authorized Project Designees in section 95976.

72. Recognition of Offset Credits for Early Action (Section 95990)

The original section 95990(a) was moved to new section 95990(b) for purposes of providing clarity within this section.

The original section 95990(c) is now new section 95990(a). These sections were moved to provide clarity within section 95990. New section 95990(a), original section 95990(c), was modified to change the dollar amount of professional liability insurance that Early Action Offset Programs must hold from two million to one million. This change was made in response to stakeholder comments that currently operated voluntary registries only hold one million dollars. This section was also modified to remove the requirements that Early Action Offset Programs track prices and counter parties. This was removed in response to stakeholder comments that Early Action Offset Programs do not have the capability to track them.

New section 95990(a)(3) now includes requirements for Early Action Offset Programs that are similar to requirements identified in section 95986(d) for Offset Project Registries. These requirements are necessary since both types of entities will be fulfilling similar functions within the offsets program, and many of these entities may be acting in both capacities.

Original section 95990(b) is now new section 95990(c). These sections were moved to provide clarity within section 95990. New section 95990(c)(3) was added to the list of original requirements. This section requires that GHG reductions or GHG removal enhancements must result from an early action offset project listed prior to January 1, 2013. Originally the timing was tied to the offset project commencement date of January 1, 2012. Staff made this change because the acceptance of early action offset credits is tied to vintage years as opposed to offset project commencement. The date was changed from 2012 to 2013 because the offset program will not be implemented by January 1, 2012. Original sections 95990(b)(5)(D) and (E) were combined into new section 95990(c)(5)(D), original section 95990(b)(5)(E)(i) was deleted, and original section 95990(b)(5)(E)(ii) was moved into new section 95990(c)(5)(D). These changes were made because once the requirement to have a conservation easement was deleted, the requirements for all the forest projects are the same and do not need to be in separate provisions. The requirement for conservation easements was deleted because it is not needed, since all projects are required to contribute to the Forest Buffer Account.

Original section 95990(d) was moved to new section 95990(j). New section 95990(d) was added to require that Offset Project Operators, Authorized Project Designees, or each holder of early action offset credits that submitted them for issuance of ARB offset credits register with ARB. All entities implementing an offset project must register with ARB to ensure the agency has all necessary information about the owners of an offset project. These requirements are similar to those for an offset project coming in directly under an ARB Compliance Offset Protocol.

Original section 95990(e) was moved to new section 95990(h)(6). New section 95990(e)(1) was added to include listing requirements for early action offset projects. These requirements are similar to those required of Offset Project Operators and Authorized Project Designees bringing in a compliance offset project under an ARB Compliance Offset Protocol. Listing is necessary to ensure that ARB has access to all information regarding early action offset projects. New section 95990(e)(2) was added to require Early Action Offset Programs to make specific information regarding early action offset projects publicly available. This is necessary to ensure that the public has access to all information regarding early action offset projects.

The changes to this section also clarify what happens to the crediting periods of early action offset projects once they transition to ARB Compliance Offset Protocols.

Section 95990(f) was modified to clarify the requirements for regulatory verification of early action offset projects. New section 95990(f)(1) includes new requirements that the verifier performing the re-verification services must be different than the one that did the initial verification for the Early Action Offset Program. This ensures that the review is completely independent and unbiased. The new requirements include a desk review of each Offset Project Data Report (new section 95990(f)(3)) by an ARB accredited verification body based on all original early action offset project documentation. A desk review by an independent body that is accredited by ARB is sufficient to determine if the information originally submitted regarding the offset project is complete and accurate. Staff has also included provisions to allow all Offset Project Data Reports for an individual offset project to be included in one desk review (new section 95990(f)(3) in response to stakeholder concerns that re-verification costs may be exceedingly high.

Section 95990 was further modified to include a threshold based on offset material misstatement in section 95990(f)(4) that, if found to be exceeded during the desk review, would trigger full offset verification services for the Offset Project Data Reports that exceed the threshold. Staff set this threshold at three percent or more, or 25,000 metric tons CO_2e ($MTCO_2e$), whichever is smaller. The 25,000 $MTCO_2e$ threshold is the same as the threshold for inclusion of covered entities in the cap-and-trade program and staff anticipates that three percent would be around this level as well. This provision allows for the same verifier that performed the desk review to conduct the full verification services, because at this point in the process staff believes that the review by the same verifier is still independent and unbiased. However, it may not be done by the verification body that did the initial verification under the Early Action Offset Program for reasons mentioned above. This provision also allows all Offset Project Data Reports that exceed the threshold and must undergo full offset verification services to be done as one verification service. This was included in response to stakeholder concerns that re-verification costs may be exceedingly high. Sections 95990(f)(4)(A) through (E) replace original section 95990(f)(3) and include all the requirements that must be met to ensure that the early action offset credits are verified according to regulatory verification requirements of all ARB offset credits, as found in section 95977.1.

Staff is seeking stakeholder comments on potential ways to facilitate the regulatory verification of early action offset credits that is efficient, does not require multiple verifiers to look at the same offset project data, and potentially provides a single, shared cost for verification services for an Offset Project Data Report.

New section 95990(g) was moved from original section 95990(f)(2) and modified so that conflict of interest is now assessed only against any party that holds more than 30 percent of the early action offset credits issued in each data year. Originally the regulation required that conflict of interest be assessed against all holders of the early action offset credits. Staff made this modification to reflect stakeholder concerns that applying conflict of interest to all early action offset credit holders is unnecessary and overly burdensome.

New section 95990(h) was added to clarify the criteria that early action offset credits must meet to be issued as ARB offset credits. These requirements are similar to the issuance requirements for ARB offset credits in new section 95981. New sections 95990(h)(1), (3), and (4) provide that ARB offset credits will be issued for those early action offset credits that meet the requirements of sections 95990(c), (e), and (f). New section 95990(h)(2) requires that all the GHG reductions or removal enhancements must be achieved by December 31, 2014. This is because beginning on January 1, 2015, all offset projects must use Compliance Offset Protocols and are no longer eligible to be brought into the compliance program if they are using Early Action Offset Program protocols approved pursuant to this section. New section 95990(h)(5) requires that Offset Project Operators, Authorized Project Designees, or each holder of early action offset credits that submit them for issuance of ARB offset credits to submit multiple attestations to ARB before any ARB offset credits are issued for GHG reductions or GHG removal enhancements achieved by the early action offset project. ARB requires these attestations in new section 95981.1 for compliance offset projects as well. These attestations are needed to specify that all listed parties specifically submit to California's jurisdiction to resolve any disputes regarding enforcement of the regulation against these parties. This change is necessary to make clear to the listed parties that by participating in California's cap-and-trade program in this capacity, they will be subject to California's jurisdiction regardless of the offset project's physical location. New section 95990(h)(6) was moved from original section 95990(e).

New section 95990(i) was added to clarify the process for how ARB offset credits will be issued for purposes of early action. New sections 95990(i)(1)(A) through (C) specify that one ARB offset credit will be issued for each early action offset credit that meets the requirements of section 95990(h) if the offsets occurred under the identified protocols in these sections. New section 95990(i)(1)(D) identify conditions that must be met for an ARB offset credit to be issued if the projects are using one of the identified protocols in this section. New section 95990(i)(1)(D)(i) requires that a portion of offset credits calculated pursuant to Compliance Offset Protocol U.S. Forest Projects be placed into the Forest Buffer Account. Like compliance offset projects, early action forest projects are also subject to reversals; therefore, these projects must also contribute ARB offset credits into the account to cover any potential losses. New section 95990(i)(1)(D)(ii) specifies that the ARB offset credits may come from a buffer account that is already being run by an Early Action Offset Program or may be subtracted from the total ARB offset credits issued at the time of conversion. The first case is identified because stakeholders have made ARB aware that some voluntary registries have already required their forest projects to contribute to a buffer account. If those registries will release the offsets to ARB, they will be accepted to meet this requirement. The second case is designed to cover those offset projects that have not contributed to a buffer account already or cannot get the offsets released to ARB by the voluntary registry. New sections 95990(i)(1)(D)(3.) and (4.) were included to identify what happens in the event that there is a reversal from an early action forest offset project. These provisions treat reversals the same way as they are treated for compliance offset projects pursuant to section 95983. This ensures that all forest offset credits are meeting the same standards.

New section 95990(i)(1)(E) provides the requirements that early action offset projects using Climate Action Reserve Forest Project Protocol, version 2.1 must meet only if they plan to transition their early action offset projects to Compliance Offset Protocol U.S. Forest Projects. If the offset project will not transition to the compliance program, they would follow the rules in section 95990(i)(1)(D). Offset projects transitioning into the compliance system must recalculate their baseline based on the requirements in Compliance Offset Protocol U.S. Forest Projects. If they would have been issued more early action offset credits after they recalculate their baseline, ARB will issue them ARB offset credits in that additional amount; otherwise they will be issued ARB offset credits on a 1:1 basis. These provisions are necessary because the project baselines for offset projects using Climate Action Reserve Forest Project Protocol, version 2.1, need to be recalculated as averaged baselines.

New section 95990(i)(2) through (4) outline the process that ARB will use to notify the Early Action Offset Program that ARB offset credits have been issued to replace their early action offset credits. These provisions are necessary so these programs can retire the appropriate offsets in their own systems, to avoid the same GHG reductions or GHG removal enhancements being credited twice in multiple systems.

New section 95990(j) was moved from original section 95990(d) and modified to include a timeframe of 15 days for ARB to notify the original holders of the early action offset credits that they have been issued ARB offset credits. This section further requires that those claiming that the early action offset credits belong to them must prove they own them and register for ARB. These steps ensure that ARB has transferred the ARB offset credits to the correct parties, and that ARB can track their participation in the market.

New section 95990(k) was added to clarify how early action offset projects transition to compliance offset projects. New sections 95990(k)(1)(A) through (C) specify that early action offset projects using Early Action Offset Program protocols identified in the provisions must use the specified Compliance Offset Protocols and must begin using the Compliance Offset Protocols by December 31, 2014. These provisions are necessary so Offset Project Operators and Authorized Project Designees know which Compliance Offset Protocols they must use and the timing for when they must transition. New section 95990(k)(1)(D) specifies that early action offset projects using Climate Action Reserve Forest Project Protocol, Version 2.1, must recalculate their baselines pursuant to Compliance Offset Protocol U.S. Forest Projects. This provision is necessary to ensure consistency across all forest projects in the compliance program. New section 95990(k)(1)(E) requires that all early action offset projects using Climate Action Reserve Forest Project Protocol versions 3.0 through 3.2 subtract any optional pools that are excluded from Compliance Offset Protocol U.S. Forest Projects beginning with the last reporting period. This provision is necessary to ensure consistency across all forest projects in the compliance program because these pools will be excluded for any new projects coming into the program beyond December 31, 2014.

New section 95990(k)(2) was added to clarify that all early action offset projects which transition to a Compliance Offset Protocol will begin a new crediting period. This provision was included to provide clarify for stakeholders on the length of eligibility for transitioned offset projects.

New sections 95990(k)(3) and (4) was added to require that once an early action offset project transitions, it must meet all the requirements that all compliance offset projects must meet if they begin under Compliance Offset Protocols. These requirements can be found in sections 95973, 95975, 95976, 95977 through 95978, 95980.1, and 95981.1. These provisions are necessary to ensure consistency across all offset projects in the compliance program beginning in the second compliance period, 2015.

New section 95990(l) was added to provide that ARB offset credits issued for early action offset credits are also subject to the invalidation provisions in section 95985. These provisions are necessary to ensure that there are replacement measures in place in the event that an ARB offset credit is found to be invalid, and also to ensure consistency across all offset projects in the compliance program beginning in the second compliance period, 2015. Further, this provision states that if an ARB offset credit that was originally an early action offset credit is invalidated, and the covered entity or retiree is no longer in business, the holder of the original early action offset credits that submitted them for issuance of ARB offset credits must replace the invalidated offsets only if they have been used for compliance or retired by ARB. These requirements are placed upon the Offset Project Operator or Authorized Project Designee for compliance offset projects; however, since a holder of the early action offset credits can apply for issuance of ARB offset credits under the early action provisions, as opposed to the Offset Project Operator or Authorized Project Designee, staff has put the onus of replacement on those parties that brought them into the compliance program.

Various minor and non-substantive clarifications were also made to section 95990 to provide consistency in terminology and ensure correct references within the regulation.

73. Sector-Based Offset Credits (Section 95991)

No modifications were made to section 95991.

74. Procedures for Approval of Sector-Based Crediting Programs (Section 95992)

No modifications were made to section 95992.

75. Sources for Sector-Based Offset Credits (Section 95993)

No modifications were made to section 95993.

76. Requirements for Sector-Based Offset Crediting Programs (Section 95994)

No modifications were made to section 95994.

77. Quantitative Usage Limit (Section 95995)

No modifications were made to section 95995.

78. Reserved for Sector-Specific Requirements (Section 95996)

No modifications were made to section 95996.

79. Reserved for Approved Sector-Based Crediting Programs (Section 95997)

No modifications were made to section 95997.

80. Jurisdiction (Section 96010)

No modifications were made to section 96010.

81. Authority to Suspend, Revoke, or Modify (Section 96011)

No modifications were made to section 96011.

82. Injunctions (Section 96012)

No modifications were made to section 96012.

83. Penalties (Section 96013)

Section 96013 was modified to include minor clarifications.

84. Violations (Section 96014)

Section 96014(b) was modified to clarify that each compliance instrument not surrendered on the appropriate surrender date is a single, separate violation. The section was also clarified to allow the violation to accrue every 45 days instead of each day the compliance instrument remains unsurrendered. These changes were made in response to stakeholder concerns about market volatility if a covered entity was required to obtain a significant number of allowances in a very short period of time, as initially drafted. These changes allow greater time to obtain the compliance instruments, and thus maintain market stability. Other clarifications were made based on stakeholder concerns regarding intent.

Section 96014(c) was added to the regulation to clarify that any act of deception in working with ARB will subject an entity to additional penalties under the provisions of this regulation. Section 96014(c) lists specific violations that may be contained in records submitted to ARB that will result in additional penalties against an entity that does not comply with the provisions of this regulation. Section 96014(d) was added to the regulation to ensure that regulated entities are aware that any violations assessed pursuant to section 96014 do not relieve the entities of their obligations under the remaining provisions of the regulation.

85. Severability, Effect of Judicial Order (Section 96020)

No modifications were made to section 96020.

86. Confidentiality (Section 96021)

No modifications were made to section 96021.

87. Jurisdiction of California (Section 96022)

Section 96022 was modified to include a provision that clarifies that any entity that participates in the market program is subject to California's jurisdiction.

88. Reserved Provisions (New Section 96023)

Section 96023 was added to reserve subsequent sections for any future rulemaking needs.

89. Modifications to Compliance Offset Protocol Urban Forest Projects

Minor, non-substantive changes were made to this protocol to ensure consistency between the regulatory requirements for offsets and the compliance offset protocols.

This protocol was also modified to clarify that offset projects on lands related to federally recognized Indian Tribes are eligible under this protocol only if the Tribes enter into a waiver of sovereign immunity with ARB related to the Tribes' participation in the requirements of this protocol and the cap-and-trade regulation. This ensures ARB's ability to pursue judicial remedies, if necessary, regarding these offset projects when enforcing the requirements of this protocol and the Cap-and-Trade Regulation; similar to ARB's ability to pursue judicial remedies regarding all other offset projects commenced under this protocol.

90. Modifications to Compliance Offset Protocol Livestock Projects

Minor, non-substantive changes were made to this protocol to ensure consistency between the regulatory requirements for offsets and the compliance offset protocols.

This protocol was also modified to clarify that offset projects on lands related to federally recognized Indian Tribes are eligible under this protocol only if the Tribes enter into a waiver of sovereign immunity with ARB related to the Tribes' participation in the requirements of this protocol and the cap-and-trade regulation. This ensures ARB's ability to pursue judicial remedies, if necessary, regarding these offset projects when enforcing the requirements of this protocol and the cap-and-trade regulation; similar to ARB's ability to pursue judicial remedies regarding all other offset projects commenced under this protocol.

91. Modifications to Compliance Offset Protocol Ozone-Depleting Substances Projects

This protocol was modified to add CFC-113 as an eligible refrigerant, and a carbon ratio was added for CFC-115. The leakage rate was changed to include the impact of California's Refrigerant Management Program. Staff also clarified that a third-party must verify compliance with the United Nations Technical and Economic Assessment Panel (TEAP) requirements.

This protocol was also modified to clarify that offset projects on lands related to federally recognized Indian Tribes are eligible under this protocol only if the Tribes enter into a waiver of sovereign immunity with ARB related to the Tribes' participation in the requirements of this protocol and the cap-and-trade regulation. This ensures ARB's ability to pursue judicial remedies, if necessary, regarding these offset projects when enforcing the requirements of this protocol and the cap-and-trade regulation, similar to ARB's ability to pursue judicial remedies regarding all other offset projects commenced under this protocol.

Minor, non-substantive changes were made to this protocol to ensure consistency between the regulatory requirements for offsets and the compliance offset protocols.

92. Modification to Compliance Offset Protocol U.S. Forest Projects

This protocol was clarified to require that the 10-year look-back at management activities on project lands is independent of past ownership, to avoid crediting a regrowth of trees that were recently harvested.

Staff made clarifications to the protocol regarding verification requirement, stating that forest projects are not eligible to receive qualified positive offset verification statements, specifying the number of sample plots to be measured and which statistical tests to use, requiring that the project acreage be verified, requiring the verification team to include a person with demonstrated competence in forest biometrics and modeling, and including requirements for less intensive verification, which requires site visits once every six years after initial verification.

This protocol was also modified to clarify that offset projects on lands related to federally recognized Indian Tribes are eligible under this protocol only if the Tribes enter into a waiver of sovereign immunity with ARB related to the Tribes' participation in the requirements of this protocol and the cap-and-trade regulation. This ensures ARB's ability to pursue judicial remedies, if necessary, regarding these offset projects when enforcing the requirements of this protocol and the cap-and-trade regulation, similar to ARB's ability to pursue judicial remedies regarding all other offset projects commenced under this protocol.

Minor, non-substantive changes were made to this protocol to ensure consistency between the regulatory requirements for offsets and the compliance offset protocols.

B. Second 15-day Change Modifications

1. Purpose (Section 95801)

No substantive changes were made to this section.

2. Definitions (Section 95802)

Definitions were added to support allowance allocation including "carbon dioxide weighted tonne," "Solomon energy intensity index," "Solomon Energy Review," and "enhanced oil recovery."

Section 95802(a)(273) was added to define tissue products in general, including tissue products manufactured using through air drying technology. The definition for "through air dried tissue," previously in section 95802(a)(265), has been removed.

Section 95802 was modified to more closely align with the federal greenhouse gas (GHG) reporting regulation's definition of carbon dioxide supplier. In addition, this section was modified to clarify that the source category is focused on upstream supply, and it does not include the listed activities and uses. Carbon dioxide used in carbon capture and geologic sequestration (CCGS) and carbon dioxide-enhanced oil recovery (CO_2-EOR) is excluded from the cap-and-trade regulation in a different way than how the federal GHG reporting regulation excludes it. Whereas the federal reporting regulation contains separate reporting categories for carbon dioxide suppliers, CCGS, and CO_2-EOR, ARB does not yet include these reporting categories within our Mandatory Reporting Regulation (MRR), though we signal in section 95852(g) that these activities and uses will be excluded from a compliance obligation through a to-be-developed quantification methodology.

Many of the modified definitions are necessary to clarify the "first deliverer" approach for the electricity sector, accommodate the inclusion of the calculation of a compliance obligation for this sector, and respond to stakeholder comments. Modifications were made to the definitions of "electricity importer," "direct delivery," "imported electricity," "purchasing-selling-entity," "qualified export "marketer," "resource shuffling," and "specified source of electricity." These changes were made to either clarify staff intent in response to stakeholder comment or to conform to changes in section 95852. A new definition of "California balancing authority" was added to accommodate clarifications made. The term "eligible renewable resource" was added, and the terms "variable renewable resource" and "replacement electricity" were deleted to reflect changes made to account for renewable portfolio standard (RPS)-eligible electricity imports. Several other definitions were modified to improve clarity.

Modification to the term "voluntary renewable electricity" was needed to correct a typographical error. Changes were also made to respond to stakeholder comments to clarify that the definition also applies to the electricity underlying the renewable energy credit (REC), and to strengthen the definition to prevent double-counting of the electricity.

The term "voluntary renewable electricity aggregator" was modified to accommodate changes made in section 95841.1.

Section 95802 was modified to include clarified definitions for terms used in revised section 95834, which contains the procedure governing beneficial holdings relationships. Definitions were modified for "Agent," "Beneficial Holding," and "Principal" to clarify the roles of the participants in beneficial holding relationships.

Several definitions relating to how compliance instruments are handled in accounts were modified for clarity. These include "Issue," "Hold," and "Retire." Finally, the definition of the term "Proceeds" was modified to reflect that proceeds will also result from sales from the Allowance Price Containment Reserve.

3. Covered Gases (Section 95810)

No substantive changes were made to this section.

4. Covered Entities (Section 95811)

Section 95811(a)(8) was modified to clarify that "oil and natural gas systems" be referred to as "petroleum and natural gas systems," to harmonize with the MRR.

Section 95811(e)(3) was clarified to identify that the term "consignee" is defined in the MRR. To avoid confusion and the potential for inadvertent non-compliance, the MRR regulation includes a clear definition of this term.

5. Inclusion Thresholds for Covered Entities (Section 95812)

Modifications were made to section 95812(c)(2)(B) in response to stakeholder comments. Modifications were made to clarify that the applicability is based on the electricity importer's sources of delivered electricity, including how this applies to specified and unspecified electricity sources.

Section 95812(c)(2)(C) was deleted because this section was no longer necessary due to the modification made in 95812(c)(2)(B).

Section 95812(c)(3) was modified to more clearly describe the threshold for CO_2 suppliers. The changes clearly state which sources of CO_2 must be included when assessing the total CO_2 for comparison against the threshold for applicability for the cap-and-trade program.

6. Opt-in Covered Entities (Section 95813)

No substantive changes were made to this section.

7. Voluntarily Associated Entities and Other Registered Participants (Section 95814)

No substantive changes were made to this section.

8. Compliance Instruments Issued by the Air Resources Board (Section 95820)

No substantive changes were made to this section.

9. Compliance Instruments Issued by Approved Programs (Section 95821)

No substantive changes were made to this section.

10. Registration with ARB (Section 95830)

Section 95830(b) was modified to consolidate several requirements concerning eligibility and restrictions into one place for clarity. New section 95830(b)(1) clarifies that entities must qualify to participate in the cap-and-trade program pursuant to 95811, 95813, or 95814 prior to registering. New section 95830(b)(2) replaces and clarifies a requirement previously contained in section 95831(a)(1) that an entity cannot apply for more than one registration. New section 95830(b)(3) replaces the original text of section 95830(b). Staff consolidated the requirements in the same section to clarify the sequence of qualifying for participation, registering, and holding compliance instruments. These modifications also address stakeholder comments indicating confusion over the requirement that each entity registers once and has only one set of accounts.

11. Account Types (Section 95831)

Section 95831(a)(1) was modified to clarify that each registered entity will have no more than one holding account, compliance account, limited use holding account, or exchange clearing holding account. The existing requirement was vague, stating only that each registered entity could gain approval for a "set" of accounts.

New section 95831(a)(4)(C) was added to clarify that the Executive Officer may transfer allowances into an account, or out of an account for surrender compliance, or when closing an account.

New section 95831(b)(2)(D) was added to be consistent with a change in section 95857(d)(1) in the first 15-day Change Notice that redirects three of the allowances submitted to fulfill an untimely surrender obligation be placed in the auction holding account.

Section 95831(b)(4) was modified to reflect a decision to direct allowances to the auction holding account rather than the Allowance Price Containment Reserve

(Reserve). Existing section 95831(b)(4)(A) was eliminated due to the change in section 95911(b)(4) that allowances remaining unsold when an auction settlement price equals the auction reserve price will be returned to the auction holding account for two consecutive auctions rather than go to the reserve. Existing section 95831(b)(4)(B) was then renumbered as section 95831(b)(4)(A). Existing section 95831(b)(4)(C) was eliminated due to the revisions to section 95857(d)(1) that redirects three of the allowances submitted to fulfill an untimely surrender obligation to the auction holding account, not to the reserve, as specified in the existing text. Section 95831(b)(4)(D) was then renumbered as section 95831(b)(4)(B).

Staff agreed to make the changes after stakeholders commented that having unsold allowances placed in the reserve would unnecessarily reduce the supply of allowances to the market.

New section 95831(c) was added to explain the procedure for closing accounts in the tracking system. New section 95831(c)(1) explains that the Executive Officer will close an entity's accounts when the entity has informed ARB that it has ceased operations, pursuant to section 95101(h). New section 95831(c)(2) creates a provision to close inactive accounts held by voluntarily associated entities on the tracking system. If these entities do not transfer allowances into or out of their accounts during a three-year period, then their accounts may be closed. This requirement is being added to ensure that the tracking system does not have to track too many dormant accounts, and so that only entities seeking to actively participate in the cap-and-trade system will register.

New section 95831(c)(3) was added to explain the procedure for dealing with accounts closed by the Executive Officer. Any compliance instruments remaining in the account that are not needed to fulfill a compliance obligation will be consigned to the auction pursuant to section 95910(d) on behalf of the registered entity.

12. Designation of Authorized Account Representative (Section 95832)

No substantive changes were made to this section.

13. Disclosure of Direct and Indirect Corporate Associations (Section 95833)

Several changes were made to the criteria determining a direct corporate association in section 95833(a)(1). These changes are intended to make the criteria for direct corporate association apply only to instances where one entity has clear control over another. Staff is proposing this change so that the imposition of joint holding and purchase limits applies only to cases where control is clear.

Section 95833(a)(1)(A) was modified so that a direct corporate association exists only when an entity holds more than 50 percent (changed from 20 percent) of any of three measures of share ownership. Section 95833(a)(1)(B) was modified so that a direct corporate association exists only when an entity holds or can appoint more than 50 percent of another entity's board of directors. Section 95833(a)(1)(C) was modified so that a direct corporate association exists only when an entity holds more than 50 percent of the voting power of another entity. Existing section 95833(a)(1)(D) was eliminated because staff agreed with stakeholder comments that the provision was too vague. Staff is proposing the changes because the previous threshold of 20 percent would have included entities without effective control over affiliates.

Section 95833(a)(2) was modified to require that two entities that are registered in the cap-and-trade program and that share a common parent not registered into the system have a direct corporate association. Staff is proposing this change to account for cases in which two registered entities are sister corporations by virtue of having a common unregistered parent. Eliminated from the section is an existing requirement involving beneficial holdings, which is no longer needed due to revisions in section 95834(c).

Section 95833(a)(3) was modified to clarify the requirements for determining whether entities have an indirect corporate association. Section 95833(a)(1)(A) was rewritten for clarity. Section 95833(a)(1)(A) was rewritten to apply the same criteria as in section 95833(a)(1), but stating that the threshold for entities having an indirect corporate association is 50 percent after multiplying the percentages at each link in a chain of direct corporate associations. Staff is proposing the changes because the previous threshold of 20 percent would have included entities without effective control over affiliates.

Section 95833(c) was modified to state that when the measures contained in sections 95833(a)(1), (2), or (3) yield a value of 25 percent or more, then the entities involved have a disclosable corporate association. Staff is proposing this change so that ARB can be aware of levels of corporate affiliation that do not indicate an entity has effective control over affiliates but nevertheless warrant regulator knowledge for market monitoring purposes. Reporting this lower level of affiliation does not result in imposition of joint holding or purchase limits.

Section 95833(d) contains the text moved from section 95833(c). In addition, section 95833(d) now includes a requirement that entities with a disclosable corporate association must provide the required information.

Section 95833(e) contains text that was moved from existing section 95833(d). The revision also changes an incorrect reference from section 95834(c) to 95833(c).

14. Disclosure of Beneficial Holding Relationships (Section 95834)

Section 95834(a)(1) was rewritten to remove the declaration that a beneficial holding relationship exists when an entity holds compliance instruments in its holding account that are owned by a second registered entity. Section 95834(a)(1) now explains the role of “agent” consistent with definition 6, which was originally contained in section 95834(a)(1)(A). Section 95834(a)(2) now explains the role of “principal” consistent with definition 209, which was originally contained in section 95834(a)(1)(B).

The text originally in section 95834(a)(2) was moved to section 95834(a)(3). The text has been modified to eliminate the notification by a utility serving as agent to ARB that a beneficial holdings arrangement exists. This requirement was replaced by the new procedure in 95834(b) that requires both the agent and principal to inform ARB of beneficial holdings relationships.

Additionally, section 95834(3)(B) was modified so that the disclosure of the beneficial holdings relationship must be confirmed by the principal in the relationship. The text, previously in section 95834(a)(2)(B), was moved to new section 95834(a)(2)(C).

Existing section 95834(a)(3) was renumbered to section 95834(a)(4). It was also modified to clarify the requirements for members of a corporate association that are establishing a beneficial holdings relationship.

Section 95834(b)(1) was modified to require both the agent and the principal in a beneficial holding relationship to report the existence of their relationship to the Executive Officer. Section 95834(b)(2) was modified to require confirmation of transfers of compliance instruments within the beneficial holding relationship. New section 95834(b)(3) states that after confirmation by the principal, compliance instruments held by the agent will count against the holding limit of the principal. Staff is proposing the changes to clarify that a beneficial holdings arrangement is an agreement and cannot exist unilaterally.

These changes to section 95834 were made for clarity.

15. Compliance Periods (Section 95840)

No substantive changes were made to this section.

16. Allowance Budgets Calendar Years 2013–2020 (Section 95841)

No substantive changes were made to this section.

17. Voluntary Renewable Electricity (Section 95841.1)

Section 95841.1(a) was modified to correct the year when allowances can begin to be retired. This change is needed to align with the modified start date of the first compliance period.

Section 95841.1(b)(1) was modified to correct the reference to the sections of the regulation which contain the eligibility requirements for renewable generators.

In section 95841.1(b)(1), an addition was made to accommodate stakeholder comments that it is not always economical for all renewable generators to register with the CEC's tracking system. The addition provides an alternative requirement for generators to meet similar stringency and verification requirements developed by the CEC.

Section 95841.1(b) was modified to respond to stakeholder comments and provide another option for documentation for the purchase and sale of qualified electricity or associated RECs.

Section 95841.1(b)(1)(F) was modified to respond to stakeholder comments and to clarify the attestation requirements that the program participant must follow.

Sections 95841.1(b)(2) and (3) were modified in response to stakeholder comment. The changes made clarify that the reporting requirements are directed toward the Voluntary Renewable Electricity participant and that the identification of the generator is the certification number. Additional modifications were made to allow for the alternative generator program requirements noted in section 95841.1(b)(1).

18. General Requirements (Section 95850)

Section 95850(b) was modified to clarify that the compliance obligation is based on the emissions that have a compliance obligation, not all emissions that are verified under the MRR.

Section 95850(c)(1) was modified to require record retention for 10 years, as was originally proposed in the 45-day regulation. This amount of time ensures that entities retain records to cover the period under which ARB could require additional compliance instruments if there were under-reporting in a previous compliance period, but only going back eight years.

Section 95850(c)(4) was added to specify that verification reports are to meet the requirements specified in the MRR.

19. Phase-In of Compliance Obligation for Covered Entities (Section 95851)

No substantive changes were made to this section.

20. Emission Categories Used to Calculate Compliance Obligations (Section 95852)

Section 95852(a)(1) was modified to clarify that the biofuel must be of a type listed in section 95852.2 and be procured in compliance with section 95852.1.1 in order to be exempt.

Section 95852(b) was modified to accommodate the calculation of the compliance obligation for first deliverers. Because this new section was added, most of the numbering within this section was changed.

New section 95852(b)(1) was in response to stakeholder comment. This section contains the calculation of a compliance obligation for first deliverers of imported electricity, which was previously contained in the MRR. A more simplified version was previously in section 95852(b)(7) of this regulation. The requirements regarding resource shuffling have been moved to 95852(b)(2).

Section 95852(b)(2) now contains the requirements to prevent resource shuffling. Modifications were made to respond to stakeholder comments regarding the use of the term “fraud.” The term “fraud” has been removed as well as other language that could impede typical electricity market activity, which was not staff’s intent. Additional language clarifies that a company’s agent must sign the attestations, as well as when the attestations must be submitted.

Section 95852(b)(3) previously addressed “replacement electricity,” which is now addressed in section 95852(b)(4). Section 95852(b)(3) now contains requirements for first deliverers to claim an emission factor from a specified source of electricity. The section was also modified to clarify what criteria must be met for electricity importers to claim a compliance obligation based on the emission factor of a specified source. A new criterion is that the electricity must be directly delivered to ensure a clear connection between the specified source and the electricity delivered into California. This section no longer requires electricity to be tracked through a contract chain of custody because stakeholder comments indicated in many cases they purchase the electricity from a marketer, and they do not always have access to all of the upstream contracts.

The previous section 95852(b)(4) was deleted because its requirements no longer apply, given changes to the accounting for specified sources of electricity. The new section 95852(b)(4) replaces the previous requirements for “replacement electricity,” and now includes an RPS adjustment. The RPS adjustment provision accomplishes the purpose of reducing a deliverer’s compliance obligation by accounting for renewable imports that staff previously addressed through the “replacement electricity” requirements. Stakeholders expressed concern with the requirement that replacement electricity would only apply to variable renewable electricity, and that the use of the term “replacement electricity” pursuant to the definitions in section 95802 required the replacement electricity to come from the same balancing authority area. Stakeholders claimed that they are mandated under State statute to meet RPS requirements and had anticipated that most, if not all of those deliveries that meet RPS requirements would avoid a compliance obligation under this regulation. Stakeholders argued that since the allocation to benefit ratepayers is based on consideration of cost burden, the “replacement electricity” provisions would unnecessarily increase ratepayer costs by requiring a compliance obligation under this regulation for electricity considered to have GHG reduction benefits under RPS mandates. Section 95852(b)(4)(B) clarifies that the RPS adjustment must be for deliveries of electricity within the reporting year. Section 95852(b)(4)(C) clarifies that the RPS adjustment is calculated by applying the default emissions rate to the eligible megawatt-hours (MWhs). Section 95852(b)(4)(D) was added to clarify that an RPS adjustment cannot be used to avoid a compliance obligation for any other source of electricity when the renewable electricity is directly delivered to the California grid. Section 95852(b)(4)(E) was added to ensure that when the California program is linked with similar programs there is no inaccurate accounting of renewable electricity that would allow the same renewable electricity to avoid a compliance obligation in multiple jurisdictions. Finally, the definition for “replacement electricity” was deleted from section 95802.

Section 95852(b)(5) was deleted and replaced with a new section, 95852(b)(5). The original section was no longer needed because the exclusion of emissions from biofuels is accomplished by the new compliance obligation equation for electricity importers.

Modifications were made to the new section 95852(b)(5), previously section 95852(b)(6). The modifications were made to detail the requirements for claims of qualified exports and the calculation of the qualified export adjustment that is a term (QE) in the equation in 95852(b)(1). This section was also modified in response to stakeholder concerns that it could be possible for resources to be shuffled, which would allow a claim for a lower emission factor and could potentially negate a valid compliance obligation. This was not staff's intent. In response to these stakeholder concerns, modifications were made to clarify the limitations of this adjustment and clarify data requirements. A modification was also made to allow claims of qualified exports, regardless of whether or not the importer is a purchasing-selling-entity (PSE), since that term is specific to e-tags.

Section 95852(b)(7) was deleted. It was no longer needed because the full equation for a compliance obligation for first deliverers of imported electricity was moved from the MRR to this regulation.

Section 95852.2(b)(18) was modified to clarify that imports by carbon dioxide suppliers and carbon dioxide supplier exports not intended for geologic sequestration do not hold a compliance obligation.

New section 95852(c)(1) was added to harmonize with the requirements for suppliers of natural gas specified in the MRR.

Section 95852(c)(2) has been modified to subtract emissions based on the utility bill-delivered gas and not on the gas reported for emission calculations. This will prevent a natural gas supplier from having a compliance obligation based on meter inaccuracies.

Section 95852(c)(3) has been modified to require that natural gas be reported in millions of British thermal units (mmBtu), not in volume.

Section 95852(c)(4) has been clarified to describe exactly how the compliance obligation for suppliers of natural gas will be calculated. The compliance obligation will be based on the supplier's reported emissions less ARB's calculated emissions from deliveries to covered entities that are customers of the supplier.

Section 95852(e)(2) was clarified to identify that the term "consignee" is defined in the MRR. To avoid confusion and the potential for inadvertent non-compliance, the MRR regulation includes a clear definition of this term.

Section 95852(g) was modified to align with the changes in the definition for carbon dioxide suppliers (section 95802).

21. Compliance Obligations for Biomass-Derived Fuels (Section 95852.1.)

Section 95852.1 was clarified to reduce redundant wording. The reference to "source categories" in this section is not relevant, as the first paragraph indicates that "this section only addresses biomass-derived fuels."

Section 95852.1(b) was modified to use the term "non-exempt biomass-derived CO_2" which is a CO_2 emission resulting from the combustion of fuel not listed under section 95852.2(a) or that is not verifiable under section 95131(i) of the MRR and is required to hold a compliance obligation.

22. Eligibility Requirements for Biomass-Derived Fuels (Section 95852.1.1.)

Provision 95852.1.1(a) was modified to clarify that, although there is no absolute requirement for biofuel contracts to meet the criteria, there is a benefit (in terms of a reduced compliance obligation) if the contract does meet the criteria. The heading of this section refers to the general term "biomass-derived fuels," and so does section (a)(1); thus this section was modified to refer to biomass-derived fuels, not only biogas and biomethane.

New section 95852.1.1(a)(1)(C) was added to accommodate the time required for certification of new RPS projects. Staff has heard from stakeholders concerned that many operators will not want to risk taking delivery of any substantial volumes of biofuel until CEC certification is received. Purchasers have an incentive to submit certification applications to the CEC promptly because certification, if granted, is backdated to the date the certification application was submitted. These modifications should also better reflect the way in which the CEC certifies facilities as RPS eligible with respect to particular fuels.

Section 95852.1.1(a)(2) was split up to make it easier to read the requirements of the provision, as well as to specify that the recovery of the fuel be destroyed without producing useful energy transfer if a facility invests in converting a flare to a generator or undertakes other equipment modification.

Previous section 95852.1.1(a)(4) was removed. Staff received several comments urging ARB to simplify the "once in, always in" concept. ARB requires annual verification of the biomass derived fuels prior to the implementation of a certification program. ARB's intent is for any adequately verified biomass-derived fuel to continue to remain eligible for the compliance exemption. Since ARB has rigorous verification requirements, and will further be developing a certification program for biomass-derived fuels, this provision is unnecessary.

Section 95852.1.1(b) was modified to clarify that a certain number of offsets can be created and sold separately from the biofuel, in addition to RECs, and the biofuel will still avoid a compliance obligation under the cap-and-trade program. Staff received several comments stating that it was not clear whether biogas projects are prohibited from claiming ARB-issued offsets or offsets from other programs. Thus, this modification was made to clarify eligibility of offsets from biomass and biogas projects.

23. Emissions without a Compliance Obligation (Section 95852.2.)

Section 95852.2(a)(1) was modified to remove confusion by referring to the methods described in the MRR regarding the biogenic fraction of solid waste materials.

Section 95852.2(a)(4)(C) was removed in response to comments received from stakeholders who claimed that tracking and enforcement of sources of wood and wood wastes is extremely difficult for energy generators. However, provisions 95852.2(a)(4)(A) and (B) remain because they are needed to report under MRR section 95103(j).

Section 95852.2(a)(8)(A) was modified to include plant, since it is identified in the definition of "biogas."

Provision 95852.2(a)(9) was moved to 95852.2(b) to clarify that the process, vented, and fugitive emissions from geothermal generating units and geothermal facilities, including geothermal geyser steam or fluids, do not hold a compliance obligation.

Provision 95852.2(a)(11) was deleted because mobile equipment emissions are not reported under the MRR.

Section 95852.2(b) was modified to delete redundant source categories and source type emissions not reported under the MRR (which should not count toward applicable reporting thresholds per section 95852.2). The modifications correct for double-counting the compliance obligation for natural gas and local distribution companies. These modifications were also made to clarify, in response to comments received, that vented and fugitive emissions from natural gas systems will be reported to ARB under the MRR and that the cap-and-trade compliance obligation for these emissions will be based on section 95122.

Section 95852.2(b)(5) was modified to specify that produced water emissions, in addition to storage tanks, are sources that must report emissions, but do not have a compliance obligation.

Section 95852.2(c) was added to the regulation to exempt emissions from military facilities from holding a compliance obligation through December 31, 2013. The Department of Defense (DoD) has raised several legal and practical issues related to its participation in the cap-and-trade program. While ARB does not agree with all of DoD's assertions, ARB will continue to evaluate options related to DoD's ability to reduce GHG emissions. ARB also recognizes that the military does not produce a product, and is therefore unable to pass the carbon cost on to a consumer or end user. These reasons combine to support a temporary exemption. This exemption allows ARB and DoD to work together to craft a direct regulation for military facilities, without potential ramifications to national security interests and that would achieve the equivalent GHG benefits of participation in the cap-and-trade program.

Various minor and non-substantive clarifications were made to section 95852.2 to ensure consistent terminology within the regulation.

24. Calculation of Covered Entity's Triennial Compliance Obligation (Section 95853)

No substantive changes were made to this section.

25. Quantitative Usage Limit on Designated Compliance Instruments—Including Offset Credits (Section 95854)

Section 95854(c) was modified to add back text that was inadvertently left out during the first 15-day changes to the regulation to apply the same quantitative usage limit to sector-based credits in both the first and second compliance periods.

26. Annual Compliance Obligation (Section 95855)

Minor clarifications were made to this section.

27. Timely Surrender of Compliance Instruments by a Covered Entity (Section 95856)

Section 95856(b)(2) was modified to clarify which vintage of compliance instruments is valid to meet a compliance obligation. The change explains that a compliance instrument from a vintage within or before the year for which a compliance obligation is calculated may be used to satisfy an annual obligation for that year. A compliance instrument issued for the last year of a compliance period, or from a previous vintage, may be used for a triennial obligation for that compliance period. The change is needed because stakeholders commented that the original text would have required entities to match vintages of allowances to emissions in a compliance period year by year, rather than for the total over the compliance period.

28. Untimely Surrender of Compliance Instruments by a Covered Entity (Section 95857)

Section 95857(b) was modified to allow entities to use offset credits to meet up to one-fourth of the untimely surrender obligation, as long as the offset usage does not violate the quantitative offset usage limits for the applicable compliance period. This modification was made in response to stakeholder comments and to clarify staff's original intent that the quantitative offset usage limit applies to the portion of offsets to meet the compliance obligation. No offsets are allowed to satisfy three-quarters of the untimely surrender obligation, since these allowances return to the auction account.

29. Compliance Obligation for Under-Reporting in a Previous Compliance Period (Section 95858)

Section 95858(c) was clarified to state that the penalty provisions in section 96014 do not apply during the six months within which the entity can obtain and surrender the compliance instruments to cover the under-reporting from a previous compliance period. This change was overlooked in the first 15-day version of the regulation.

Section 95858(d) was added to limit the requirement to surrender compliance instruments for under-reporting to the previous eight years. This change was in response to stakeholder comments.

Also, various minor and non-substantive clarifications were made to section 95858.

30. Disposition of Allowances (Section 95870)

The timing of allowance allocation activities was updated in section 95870(a), (b), (c), and (d) in response to stakeholder comment. Allocation to accounts controlled by the Executive Officer will now occur immediately after the creation of these accounts. Allocation to electrical distribution utilities and industrial covered entities will now occur in November of the year prior to the allowance budget year being distributed. A special allocation of 2013 vintages to electrical distribution utilities is now planned in July 2012, to allow for consignment auctions by utilities of one-third (one-sixth at each of two auctions) of 2013 allowances in 2012.

A new approach for allocation to the petroleum refining sector was inserted in section 95870(d)(2)(A-B) in response to stakeholder comment. In the first compliance period, a total amount of allowances will now be assigned to the refining sector. This sector allocation will then be divided among individual refiners using the new method specified in section 95891(d).

In the second and third compliance periods, there will no longer be a sector allocation determined for the refining sector. The amount allocated to each individual refinery will be based on the product output-based allocation approach and the "CO_2 weighted tonne" benchmark. These changes and the associated impacts are detailed in Appendix A.

Based on additional information provided by stakeholders, Table 8-1 was updated with changes to the oil and gas extraction and tissue manufacturing activity categories, and to reclassify coke calcining as a high-leakage risk activity.

Section 95870 Table 8-1 was modified to define tissue manufacturing as a leakage-exposed activity, which includes tissue manufacturing using through air dried technology.

31. General Provision for Direct Allocations (Section 95890)

No substantive changes were made to this section.

32. Allocation for Industry Assistance (Section 95891)

Section 95891(a) was updated to indicate that the choice of allocation methodology is based on classification of "activities" rather than "industries" in Tables 8-1 and 9-1. This change clarifies that a facility within a given industry may conduct multiple activities and that the operator of a facility may receive allocation under both the product-based and energy-based allocation methodologies (based on the assigned allocation approach for each separate activity). The assignment of allocation method was also updated to allow for the new petroleum-refining approach created in 95891(d).

The nomenclature in the equation for the product output-based allocation calculation methodology was changed slightly to improve clarity.

The energy-based allocation calculation methodology specified in section 95891(c) was modified based on stakeholder comment. The text was updated to clarify that the combined heat and power (CHP) exclusion in the "steam consumed" term applies only to steam produced from CHP units on site. Allocations for on-site CHP unit activities are captured in the $F_{Consumed}$ term. Steam imported from an off-site CHP unit is included in the $S_{Consumed}$ term. The "electricity sold" term was altered slightly to clarify that this term captures all power exported or sold from a facility. The subscripts for the assistance factor and cap decline factor were updated to show that these factors vary by activity, rather than by sector.

In section 95891(d), a new methodology for allocating to individual operators in the petroleum-refining sector in the first compliance period was added in response to stakeholder comments about the impact of the prior proposal on equity in the refining sector in the first compliance period.

Under the new text, complex refiners' allowances are allocated based on a methodology initially proposed by the Western States Petroleum Association. This approach allocates allowances based on the following factors: (1) historical emissions from for each refinery, (2) the Solomon Energy Intensity Index (EII) for each refinery, (3) an adjustment factor to reduce competitiveness impacts of allowance allocation between in-state refineries, and (4) future emissions for each refinery.

The Solomon EII is a complexity-adjusted measurement of refinery energy efficiency developed by Solomon Associates. Solomon Associates has been developing energy-efficiency benchmarking relied upon by the industry for the past 30 years. They maintain an extensive database of more than 500 refineries' energy consumption and process data, covering over 85 percent of global refining capacity, which is used to develop the EII values. The Solomon EII is the industry standard for comparing energy efficiency across refineries globally. California refineries that have a Solomon EII value represent over 90 percent of refining capacity in the State.

Staff believes that the EII is the most appropriate performance metric for complex facilities in the first compliance period. This metric is well understood by all complex facilities and has been recognized under the U.S. Environmental Protection Agency's (EPA's) ENERGY STAR Program.

Simple refineries that do not have an EII value, or those without a representative EII value as determined by the Executive Officer, are allocated to using the "simple barrel" product benchmark proposed in the first 15-day package. The value for this simple benchmark has been updated from 0.0465 allowances/barrel of primary refinery products to 0.0462 allowances/barrel. This change was made to reflect additional data provided by covered refineries and the inclusion of 2010 data in the development of the benchmark. A limit on the amount of allowances a facility can receive was imposed based on historical emission levels consistent with stakeholder comments. This will prevent any excessive rewards due to free allocation under the simple barrel metric.

For the second and subsequent compliance periods, the new text allocates to all refiners using the “Carbon Dioxide Weighted Tonne” approach. This metric is based on the refinery benchmarking conducted for the European Union’s Emissions Trading Scheme. See Appendix A for more information on refinery allocation.

Product-based emissions efficiency benchmark values in Table 9-1 were updated based on stakeholder comment. Section 95891 Table 9-1 was modified as follows:

- New product metrics were created for the oil extraction and petroleum refining sectors.

- The hydrogen production benchmarks were updated to ensure equity between merchant hydrogen plants and refinery-owned hydrogen production allocated to using the “Carbon Dioxide Weighted Tonne” metric.

- The tissue benchmark was modified to: (1) redefine benchmarked product unit, and (2) to correct a unit conversion error. With the information collected from stakeholders, staff initially believed that there were two tissue manufacturing facilities that used through air drying (TAD) technology. However, during the 15-day comment period, it was brought to staff’s attention that there is one facility that used the TAD technique and another facility that used the conventional technique. Working with stakeholders, staff gathered information on different tissue manufacturing technologies to redefine the product unit. Staff concludes that the tissue produced from a TAD dryer and conventional dryer have reasonably comparable functionality, even though TAD tissues are high-end products with superior softness, fluffiness, and absorbency. Staff also modified the benchmark value by correcting errors caused by a product unit conversion (metric tons to short tons).

- The linerboard benchmark was modified because staff obtained more precise data sets from a facility that manufactures linerboard.

- The medium benchmark was modified to correct the typographical error in the third decimal place.

- The cement benchmark was modified to correct the amount of clinker consumed for the best-in-class (benchmark) facility. In the benchmarked year, this facility blended and consumed some amount of clinker produced in the previous year. The previous year amount was not properly accounted for in the initial calculation. Staff corrected the error.

- The tin steel plate production benchmark was modified because of an erroneous calculation. Two years' worth of emissions had been mistakenly removed from the numerator in the initial benchmark calculation. This error made the benchmark number significantly lower than intended. Staff corrected the error.

In section 95891, Table 9-2 was modified to define "sectors and activities associated with process emissions greater than 50 percent", rather than "cement manufacturing." In the previous proposal, staff identified only cement manufacturing as an activity associated with a significant level of process emissions for which no cost-effective abatement opportunities are currently available. However, stakeholders in other sectors whose activities also release process emissions raised a concern in comments. After careful consideration, staff determined that sectors with activities that are associated with process emissions greater than 50 percent are eligible for a lower cap adjustment factor, taking into consideration the potential impact from the emissions that do not currently have cost-effective abatement opportunities.

33. Allocation to Electrical Distribution Utilities for Protection of Electricity Ratepayers (Section 95892)

Section 95892(a) was updated to show how the amount allocated to an individual electrical distribution utility will be calculated based on the total sector allocation and Table 9-3.

In section 95892(b), the language was modified to fully include electrical cooperatives and to clarify that publicly owned utilities (POUs) and cooperatives may only ask for allocations to be placed into compliance accounts of facilities they (or a Joint Powers Agency) operate.

Section 95892(c) was clarified so that all allowances placed into limited use holding accounts must be offered at the consignment auction, not just those controlled by investor-owned utilities (IOUs).

Section 95892(d) was changed so that equal limitations apply to both the use of auction proceeds from the sale of allowances and the value of allowances freely allocated and used for compliance.

Section 95892(d)(3)(A) was moved to 95892(d)(4).

Text addressing rebates of allowance value in Section 95892(d)(3)(B and C) was removed because staff determined this language suggested a particular requirement for use of auction proceeds, and ARB does not have authority to appropriate funds. The use of revenue obtained from consignment of allowances is the responsibility of the

California Public Utilities Commission (CPUC) for investor-owned utilities and the governing Boards of publicly owned utilities.

Section 95892(e) was modified to clarify how utilities will report the use of allowance value to ARB.

Table 9-3 was updated to correctly identify several electrical distribution utilities (EDU) as Investor- Owned Utilities or Rural Electricity Cooperatives. The apportionment of allowance value was also changed based on stakeholder comment and improved availability of end-use customer load data for Western Area Power Administration (WAPA) and Lassen utility districts. After reviewing the discussion included in Appendix A to the last round of 15-day changes, WAPA identified a misspecification in their accounting of end-use customer load and provided an updated profile of their historical resource mix. After careful review, staff determined that it was appropriate to update the load forecasts for WAPA and Lassen. These changes resulted in very minor redistributions of allowance value. Additionally, edits were made to correct formula and data entry errors included in the previous version of the workbook used to populate table 9-3. These changes resulted in a minor redistribution of allowance value for all utilities.

34. Reserved for Allocation to Natural Gas Distribution Utilities for Protection of Natural Gas Ratepayers (Section 95893)

No substantive changes were made to this section.

35. Auction of California GHG Allowances (Section 95910)

Section 95910(c) was modified to clarify the process used for the two auctions that will be conducted each quarter. Section 95910(c)(1) was modified to clarify that the auction of allowances from the current budget year may also include allowances from earlier budget years. This provision is needed to accommodate the two other changes. First, allowances remaining unsold at auction will be returned to auction for two consecutive auctions instead of being sent to the reserve. Second, allowances used to fulfill an untimely surrender obligation will go to the auction holding account, not the reserve. Both of these changes may result in older vintage allowances being auctioned.

The requirement that, beginning in 2013, one quarter of the allowances allocated for auction each budget year will be offered at each auction was moved from section 95910(c)(1) to new section 95910(c)(1)(A). New section 95910(c)(1)(B) clarifies that allowances consigned to the auction pursuant to 95870(f) will also be sold at the current vintage auction. New section 95910(c)(1)(C) clarifies that allowances remaining unsold at previous auctions may also be returned to the current vintage auction pursuant to section 95911(b)(4).

Section 95910(c)(2)(B) was modified to clarify that one-quarter of the future vintage allowances designated for auction in each budget year will be offered at each auction. New section 95910(c)(2)(C) clarifies that allowances remaining unsold at previous future vintage auctions may also be returned to the future vintage auction, pursuant to section 95911(b)(4).

Section 95910(d)(2) was modified to correct a reference to the source of allowances when accounts are closed.

36. Format for Auction of California GHG Allowances (Section 95911)

Section 95911(b)(3)(A)3 is modified to reflect changes to section 95911(b)(4), which makes allowances unsold at auction eligible for re-auction at a later time, instead of being redirected to the Allowance Price Containment Reserve (Reserve).

The existing text in section 95911(b)(4)(A) redirected unsold allowances to the reserve. This text was replaced with a provision to return unsold allowances to the auction holding account. The modified section now allows for them to be re-auctioned after two consecutive auctions reach an auction settlement price above the auction reserve price. Existing section 95911(b)(4)(B), which returned allowances unsold at future vintage auctions to the auction holding account, was also removed. This section was replaced by new section 95911(b)(4)(B), which returns unsold future vintage allowances to the auction holding account, and includes the provision that they can be re-auctioned after two consecutive future vintage auctions reach an auction settlement price above the auction reserve price.

Staff included the modifications to section 95911(b)(4) after many stakeholders observed that redirecting unsold allowances to the reserve when a market is initially over-allocated may result in the market being artificially short in later years. Staff agreed that the original provisions could make the market tighter, at least until market prices rose to the level of the reserve tier prices. Staff believes the delayed release mechanism will ensure that any initial over-allocation could be remedied without a significant effect on prices.

New section 95911(b)(4)(C) added a provision concerning allowances that return to the auction holding account if they remain unsold when an auction settlement price equals the auction reserve price. Staff is proposing that the allowances will be re-auctioned at a later date. However, returning too many allowances to a single auction could result in the auction being oversupplied yet again. Staff is proposing a limit on the number of allowances sent back to each auction, equal to no more than 25 percent of the number of allowances already designated for a particular auction. This provision would spread the supply of re-auctioned allowances over multiple auctions.

Section 95911(c)(4)(A) was modified to raise the purchase limit for the first compliance period from 10 percent to 15 percent for industrial entities. Staff determined the change was needed after reviewing new data on emissions and in response to comments, the entry of new facilities, and the effect of the allocation of allowances by ARB on net compliance needs.

37. Auction Administration and Registration (Section 95912)

No substantive changes were made to this section.

38. Sale of Allowances from the Allowance Price Containment Reserve (Section 95913)

Section 95913(f)(3)(B) was modified to clarify that the price charged for an allowance is the price of the tier from which it was purchased, not the bid actually submitted. The change is necessary because the process allows bids to a higher tier to be fulfilled with allowances from a lower-priced tier if they are available. Staff agrees with stakeholders who commented that the procedure did not specify whether the bid or the tier price is to be used.

39. Disclosure of Direct and Indirect Corporate Associations (Section 95914)

Section 95914(e)(1) and (2) are modified to reflect the changes in section 95833 governing the process for determining when a corporate association exists. Instead of there being a single category of “disclosable” corporate association, there are three separate categories of association. The lower level of association, disclosable, does not result in a joint purchase limit for its members. The same change was made to section 95914(e)(3).

Section 95914(e)(2)(C) was modified to correct the calculation of the purchase limit for each member of a corporate association. The member’s purchase limit should equal the entity’s allocated share of the association’s limit times the purchase limit, not the number of allowances auctioned.

Section 95914(e)(3)(A) was modified to clarify the process used when an association does not allocate shares of the purchase limit among its members.

40. Trading (Section 95920)

Section 95920(a) was modified to clarify that the holding limit will be applied to a group of entities with a direct or indirect corporate association. The change was needed to reflect a change to the classification of corporate associations in section 95833(a).

Section 95920(b) was modified to replace the term “transaction” with the term “transfer request.” The change is needed to clear up confusion between the act of transferring control of a compliance instrument on the tracking system and the underlying agreement in the secondary market between entities which would result in a transfer. This change was made to sections 95920(b)(3) and (4).

The term “transaction” means an understanding among registered entities to transfer the control of an allowance from one entity to another, either immediately or at a later date. The “transfer” of a compliance instrument means the removal of the serial number of a compliance instrument from one account and placement into another account. In the California cap-and-trade program, a transfer will be effected through a “Transfer Request” submitted by an authorized account representative or an alternate authorized account representative to the accounts administrator to register a transfer of allowances between accounts into the tracking system.

Section 95920(b)(4) was also modified to update a reference to section 95921. This change was needed to reflect modifications to section 95921.

Section 95920(c) was modified to clarify how the holding limit will apply to allowances that can be used for compliance in the current compliance year separately from those that cannot be used for compliance. Section 95920(c)(1) was modified to clarify a reference to section 95856(b), which defines the vintages that can be used for current compliance.

Section 95920(c)(1)(A) was modified to clarify that, in any year, allowances from previous years may be used for compliance. Section 95920(c)(1)(C) was modified to clarify that allowances purchased at the advance auction may be usable during the current compliance year, but not the current compliance period.

Section 95920(c)(2) was modified to be consistent with section 95856(b), to state that the ability to use allowances changes with each year, not with each compliance period. That is, vintage 2015 allowances could be used for compliance surrender in 2016, but vintage 2016 and 2017 allowances that had been purchased at advance auction could not.

Section 95920(f) was eliminated because changes to section 95920(a) render the section redundant.

Existing section 95920(g) was renumbered to section 95920(f). Section 95920(f)(1) was modified to clarify that the holding limit is applied only to allowances, not all compliance instruments. In addition, the holding limit applies jointly to members of direct and indirect corporate associations, not to members of a disclosable corporate association. This change was also made to sections 95920(f)(2), (3), and (4).

Section 95920(f)(4) was modified to use the newly defined term “transfer request” in place of the term “transaction.” This was to clarify that the accounts administrator will not accept deficient transfer requests. Some stakeholders expressed concern that the provision would require the automatic unwinding of the transaction that resulted in the transfer request.

Section 95920(h) was renumbered to section 95920(g) and clarified so that the holding limit will evaluate a beneficial holding by an agent against the holding limit of the principal for whom it is held.

41. Conduct of Trade (Section 95921)

Sections 95921(a)(1) and (2) were modified to clarify that all requests for transfer of compliance instruments between accounts on the tracking system must meet the requirements of this article before the accounts administrator will register them into the tracking system. The changes were needed to emphasize the distinction between the transfer request and the underlying transaction that results in the request. Existing section 95921(b) was replaced completely. Stakeholders expressed concern that the text would have required them to automatically unwind the underlying transaction if the accounts administrator determined the transaction violated a requirement. New section 95921(b) outlines the procedure to be followed when the accounts administrator finds a deficiency in the transfer request submitted pursuant to 95921(a).

New section 95921(b)(1) describes the procedure when a deficiency is detected in a transfer request before it is recorded into the tracking system. New section 95921(b)(1)(A) requires the accounts administrator to inform both the Executive Officer and the entity submitting the request of the deficiency. New section 95921(b)(1)(B) states that the entities submitting the request may resubmit the request with the deficiency corrected within the three-day time limit set pursuant to section 95921(a)(1)(A). New section 95921(b)(1)(C) states that if entities fail to submit the corrected transfer request within the time limit, they must either withdraw the transfer request or submit a new request for transfer.

Staff created this procedure to ensure that some quality control checks are made when a transfer request is submitted. Staff anticipates that most deficiencies will be minor, such as failure to include correct account numbers, compliance instrument serial numbers, or other required information fields. Staff believes that these problems should be remedied within the existing requirement to submit a transfer request within three days of the settlement of a transaction that results in a request for transfer.

Staff also intends to develop the capacity to make checks for compliance with other rules, such as holding limits, prior to registering the transfer into the tracking system.

Whether the entity submitting the deficient transfer request corrects the deficiency before or after the transfer is recorded into the tracking system, staff has proposed the above changes to ensure that either the correction is made or the transfer will be reversed on the tracking system. Ultimately, ARB must be able to use its control over the recognition of transfers between accounts as the final method of ensuring compliance with the regulation.

New section 95921(b)(2) was added to describe the procedure to be used when the accounts administrator detects a deficiency in a transfer request after it is recorded into the tracking system. New section 95921(b)(2)(A) requires the accounts administrator to inform both the entities submitting the request and the Executive Officer of the deficiency. New section 95921(b)(2)(B) provides the entities that submitted the deficient transfer request five business days to correct the deficiency before the Executive Officer may instruct the accounts administrator to reverse the transaction on the tracking system.

Existing section 95921(b)(3) was removed, as it is not necessary to restate ARB's existing penalty provisions.

Minor modifications were made to section 95921(c) to clarify the information submitted with each transfer request and that the request must be submitted before any transfer is recorded into the tracking system. A requirement for the transfer request to include the time of the transaction and transaction settlement was removed from sections 95921(c)(1) and (2). Staff agrees with stakeholders who commented that these times are not meaningful for many transactions and should not be required.

Section 95921(e) was modified to deal with cases in which a registered entity may acquire and hold allowances on behalf of another entity. Section 95921(e)(1) was modified to remove a prohibition on transactions in which parties fail to disclose ownership interests in the compliance instruments involved. The replacement text states that an entity cannot purchase and hold allowances for another entity except when part of a beneficial holdings relationship disclosed to the Executive Officer pursuant to section 95834. This modification is needed to clarify to entities when they must create and disclose a formal beneficial holding relationship.

New section 95921(e)(2) states that if an entity acquires a compliance instrument on behalf of another entity that is not part of a disclosed beneficial holdings relationship, then the entity cannot hold that instrument but must immediately transfer it to the other entity by specifying the other entity's account number in the transfer request. This provision is added to allow agents to purchase on behalf of clients, as long as they do not hold the instruments in their own accounts.

The text for existing section 95921(2) was renumbered to 95921(e)(3).

New section 95921(g) modifies the information required for transfer requests when submitted by holders of exchange clearing holding accounts. New section 95921(g)(1) exempts these entities from having to include dates, prices, and beneficial holdings information in transfer requests. This information would be in the transfer requests submitted by the entities using the exchange clearing accounts to transfer control of compliance instruments. Staff agrees with stakeholders who commented that requiring this information would be an unnecessary requirement.

New section 95921(g)(2) requires that holders of exchange clearing holding accounts must retain transactions records, including the information listed in 95921(c), for 10 years. New section 95921(g)(3) requires the holders of these accounts to make records available within 10 days of a request from ARB. These provisions allow ARB access to transaction data when needed for investigation while reducing the duplication of information in the tracking system.

42. Banking, Expiration, and Voluntary Retirement (Section 95922)

No substantive changes were made to this section.

43. General Requirements (Section 95940)

No substantive changes were made to this section.

44. Procedures for Approval of External GHG ETS (Section 95941)

No substantive changes were made to this section.

45. Approval of Compliance Instruments from External GHG ETS (Section 95942)

No substantive changes were made to this section.

46. Reserved for Linkage (Section 95943)

No substantive changes were made to this section.

47. General Requirements for ARB Offset Credits (Section 95970)

Minor and non-substantive clarifications were made to section 95970.

48. Procedures for Approval of Compliance Offset Protocols (Section 95971)

A numbering structure was added to this section to support the inclusion of new provisions in this section. New section 95971(b) was added in response to stakeholder comments to include a periodic review of approved Compliance Offset Protocols.

49. Requirements for Compliance Offset Protocols (Section 95972)

Section 95972(a)(4) was modified in response to stakeholder comments and to clarify that Compliance Offset Protocols can be approved if they can eliminate the conditions that pose a risk of leakage.

Section 95972(a)(9) was modified in response to stakeholder comments and to clarify that eligibility will be based on a standardized approach and not a project-specific approach.

Also, various minor and non-substantive clarifications were made to section 95972.

50. Requirements for Offset Projects Using ARB Compliance Offset Protocols (Section 95973)

Section 95973(a)(2) was modified in response to stakeholder comments that the language was unclear in how it applies to early action offset projects transitioning to Compliance Offset Protocols. Section 95973(c) specifies that these early offset projects may have an earlier offset project commencement date.

Also, various minor and non-substantive clarifications were made to section 95973.

51. Authorized Project Designee (Section 95974)

Section 95974(a)(2) was modified to clarify additional responsibilities an Offset Project Operator may delegate to an Authorized Project Designee. This change allows an Authorized Project Designee to perform additional administrative functions on behalf of the Offset Project Operator.

52. Listing of Offset Projects Using ARB Compliance Offset Protocols (Section 95975)

Section 95975(l)(1) was modified to clarify that the limited waiver of sovereign immunity must include a consent to suit by the State of California, Air Resources Board, rather than a consent to suit independently by ARB and/or the State of California. This change was made in response to stakeholder comments and is necessary to ensure the requirements of the waiver pertain clearly to ARB as part of the State of California.

An additional modification in section 95975(l)(3) was added to acknowledge the fact that federal approval may not always be necessary for projects located on Indian lands, as defined by 25 U.S.C. section 81(a)(1), and that the Tribe will need to provide ARB with documentation to either demonstrate approval or show that approval is not required. This change was made in response to stakeholder comments and is necessary to clarify the requirement.

Various minor and non-substantive clarifications were made to section 95975.

53. Monitoring, Reporting, and Record Retention Requirements for Offset Projects (Section 95976)

Section 95976(a) was modified in response to stakeholder comments that the regulation should recognize that some protocol-specific monitoring equipment requirements exist in ARB's Compliance Offset Protocols.

Also, various minor and non-substantive clarifications were made to section 95976.

54. Verification of GHG Emission Reductions or GHG Removal Enhancements from Offset Projects (Section 95977)

Section 95977(b) was modified in response to stakeholder comments that annual verifications for offset projects that produce very few offset credits each year are a significant cost burden. Staff agrees with these comments and included a threshold that projects must meet to qualify for a two-year verification cycle.

Also, various minor and non-substantive clarifications were made to section 95977.

55. Requirements for Offset Verification Services (Section 95977.1.)

Section 95977.1(b)(2) was modified to clarify the timing for submitting an update to a conflict-of-interest evaluation, to ensure that the most accurate information related to the verification team for an offset project is available and meets the conflict-of-interest requirements for the regulation.

Section 95977.1(b)(3)(A) was modified to require the Offset Project Developer or Authorized Project Designee to make all relevant offset project information available to the verification team.

Section 95977.1(b)(3)(B) was clarified to indicate key dates included as part of an offset project verification.

Section 95977.1(b)(3)(C) was clarified with a title to specify key discussions a verification team must have with the Offset Project Operator or Authorized Project Designee.

Section 95977.1(b)(3)(D) was modified to accommodate the changes to the offset verification cycle for small projects in section 95977(b).

Section 95977.1(b)(3)(D)(2.)(i.) was modified in response to stakeholder comments to allow flexibility to the verification team to conduct some verification services offsite and not during the time spent at the offset project site.

Section 95977.1(b)(3)(I) was modified to require a verification team to clearly show how the riskiest sources of offset project information were reviewed for accuracy. This is needed to provide written documentation that the verification team fulfilled its regulatory verification requirements.

Section 95977.1(b)(3)(R)(4.)(a.) was modified to clarify the timing of the submittal of the detailed verification report to the Offset Project Developer, Authorized Project Designee, or Offset Project Registry. This change was needed to ensure that the detailed verification report was completed and finalized at the same time as the Offset Verification Statement.

Section 95977.1(b)(3)(V) was modified to include additional information a verification body must provide to ARB or an Offset Project Registry as part of oversight of the verification program. This change is necessary to ensure that offset verification service costs are commensurate with the complexity of the offset project being verified.

Also, various minor and non-substantive clarifications were made to section 95977.1.

56. Additional Project-Specific Requirements for Offset Verification Services (New Section 95977.2.)

No substantive changes were made to this section.

57. Offset Verifier and Verification Body Accreditation (Section 95978)

No substantive changes were made to this section.

58. Conflict-of-Interest Requirements for Verification Bodies for Verification of Offset Project Data Reports (Section 95979)

Section 95979(b)(2) was modified to apply conflict-of-interest requirements on the previous five years of activity between an offset verifier and Offset Project Operator or Authorized Project Designee, to add integrity to the offset verification program and align with similar requirements in the MRR.

Section 95979(b)(4) was clarified regarding when the same offset verification body can provide offset verification services to the offset project and to align with similar requirements in the MRR.

Section 95979(c) was modified to align the time period with the requirements in 95979(b)(2), but for instances where there is a potential for a low conflict of interest.

Section 95979(f)(3)(A) was modified to state that if an emerging conflict of interest can be mitigated and is disclosed to ARB, then the verification body will not be subject to revocation or suspension proceedings. This change was necessary to clarify that timely notice and mitigation of an emerging conflict of interest would not jeopardize the accreditation of a verification body.

59. Issuance of Registry Offset Credits (Section 95980)

New section 95980(b) was added to include a deadline for an Offset Project Registry to determine the completeness of a submission by a project operator.

Original section 95980(b), now section 95980(c), was modified to clarify when the initial crediting period for an early action offset project that transitions to a Compliance Offset Protocol begins.

60. Process for Issuance of Registry Offset Credits (New Section 95980.1.)

Section 95980.1(a) was modified to support the inclusion of the completeness deadline added to new section 95980(b) and allow the Offset Project Registry 15 days after its determination to issue registry offset credits.

61. Issuance of ARB Offset Credits (Section 95981)

New section 95981(c) was added in response to stakeholder comments requesting that staff include a deadline for ARB to determine the completeness of a submission by a project operator.

Original section 95981(d), now section 95981(e), was modified to clarify when the initial crediting period for an early action offset project that transitions to a Compliance Offset Protocol begins.

Also, various minor and non-substantive clarifications were made to section 95981.

62. Process for Issuance of ARB Offset Credits (Section 95981.1)

Section 95981.1(a) was modified to support the inclusion of the completeness deadline added to new section 95981(c) and to allow ARB 15 days after its determination to issue ARB offset credits.

Section 95981.1(d) was modified to shorten the time period from 30 to 15 days for ARB to notify project operators that the information they submitted was incomplete and request additional information. This change was made in response to stakeholder comments that the process for the ultimate issuance of ARB offset credits was too lengthy.

Also, various minor and non-substantive clarifications were made to section 95981.1.

63. Registration of ARB Offset Credits (Section 95982)

No substantive changes were made to this section.

64. Forestry Offset Reversals (Section 95983)

Sections 95983(c)(3) and (c)(4) were modified to make it clear that ARB offset credits must only be replaced if there have been ARB offset credits issued to the offset project. Also, in response to stakeholder comments, staff changed the timing for replacing the reversed tons in section 95983(c)(3), new section (c)(3)(B), and new sections 95983(c)(4)(2) and (c)(4)(3), from 90 days to six months. This will alleviate concerns that entities will not have enough time to find sufficient compliance instruments.

New section 95983(d)(1) was added to clarify that ARB will compensate for reversals out of the Forest Buffer Account in the case of project termination due to unintentional reversal. This will ensure that permanence obligations are fully upheld for all GHG reductions or removal enhancements achieved by the offset project.

Also, various minor and non-substantive clarifications were made to section 95983.

65. Ownership and Transferability of ARB Offset Credits (Section 95984)

No substantive changes were made to this section.

66. Invalidation of ARB Offset Credits (Section 95985)

Section 95985(b) was modified and now focuses only on clarifying the timeframe in which ARB may invalidate ARB offset credits. The eight year statute of limitations in original section 95985(b) was moved to new section 95985(b)(1). The other part of original section 95985(b,) regarding what may trigger invalidation, was moved to new section 95985(c). Original section 95985(b)(1) was deleted in response to stakeholder comments that ARB would invalidate an ARB offset credit based on clerical errors and any errors that would not affect the number ARB offset credits that were issued.

Original section 95985(b)(2) was moved to new section 95985(c)(1). New sections 95985(c)(1)(A) through (c)(1)(C)(3.) were added to include a process by which ARB would determine if there was an overstatement in the number of GHG emission reductions and GHG removal enhancements that were credited with ARB offset credits. This includes a notification process and identifies the information that ARB will look at to determine if there was an overstatement. New section 95985(c)(1)(B) was added to provide the equation that ARB will use to determine the amount of the overstated GHG reductions and GHG removal enhancements. All provisions in sections 95985(c)(1) were added in response to stakeholder comments that invalidating all of the ARB offset credits associated with an Offset Project Data Report is overly burdensome and unnecessary to maintain the environmental integrity of the program.

Original section 95985(b)(3) was moved to new section 95985(c)(2). Original section 95985(b)(4) was moved to new section 95985(c)(3).

Original section 95985(b)(5) was deleted and replaced with new section 95985(b)(1)(A). The statute of limitations was changed from five years to three years for ozone depleting substances projects, because ARB believes that three years is sufficient time for any new information regarding an Offset Project Data Report for that project type to be discovered.

Original section 95985(b)(6) was deleted and replaced with new section 95985(b)(1)(B). These new provisions clarify that offset projects developed under the other three Compliance Offset Protocols may also qualify for a three-year statute of limitation if a different verification body verifies a subsequent Offset Project Data Report from that offset project within three years. This provision provides some flexibility to Offset Project Operators to switch verification bodies before the six-year verification body rotation requirement is reached, so that the project can be reviewed by a different verifier, which could bring to light any irregularities in the offset project data or confirm the validity of the offset project implementation and subsequently issued ARB offset credits.

Original section 95985(b)(7) was moved to new section 95985(c)(4)(A). New section 95985(c)(4)(B) was added to clarify that reversals for forest offset projects do not trigger an invalidation, and that reversals will be handled according to section 95983. This provision was added to alleviate stakeholder concerns that any reversal would trigger invalidation and that the forest owner would have to double compensate for those tons.

New section 95985(d) was added to immediately block any transfers of ARB offset credits after ARB makes an initial determination to investigate the applicable Offset Project Data Report. This provision will prevent the holders of potentially invalidated ARB offset credits from transferring them (and any associated replacement liability) to other unwitting parties.

Original sections 95985(c) through (c)(3) were moved to new sections 95985(e) through (e)(3).

Original sections 95985(d) through (d)(4) were moved to new sections 95985(f) through (f)(4). New section 95985(f)(4)(A) was added to provide notice of ARB's final determination to invalidate ARB offset credits to affected parties. New section 95985(f)(4)(B) was added to provide notice of ARB's final determination to invalidate ARB offset credits to programs that are linked with California's cap-and-trade program.

Original sections 95985(e) and (e)(1) were moved to new sections 95985(g) and (g)(1). New sections 95985(g)(1)(A) and (g)(1)(B) were added to support the new provisions added in section 95985(c)(1). If ARB invalidates only a portion of the ARB offset credits from an Offset Project Data Report, ARB must determine how many and which ARB offset credits to remove from each parties Compliance and/or Holding Accounts. The formula in section 95985(g)(1)(A)(1.) will be used to determine how many ARB offset credits will be removed from the accounts of the affected parties, and section 95985(g)(1)(A)(2.) will be used to determine which ARB offset credits will be removed from the accounts of the affected parties.

New section 95985(g)(1)(B) was added to make clear that, if ARB offset credits are invalidated due to either reason in section 95985(c)(2) or (c)(3), all of the ARB offset credits in Holding and/or Compliance Accounts for the applicable Offset Project Data Report will be invalidated. The intent of this requirement did not change; however, stakeholders wanted the language to be more clear.

Original section 95985(e)(3) was deleted because these parties are covered under new section 95985(g)(2).

Original sections 95985(e)(2) and (e)(4) were moved to new sections 95985(g)(2) and (g)(3) respectively.

Original section 95985(f) was moved to new section 95985(h). A numbering structure was added to new section 95985(h) for readability and the addition of new provisions under this section. New section 95985(h)(1) clarifies that only ARB offset credits in the Retirement Account must be replaced by the parties identified in section 95985(e)(2). New section 95985(h)(1)(A) was added to support the new provisions added in section 95985(c)(1). If ARB invalidates only a portion of the ARB offset credits from an Offset Project Data Report, ARB must determine, through the formula in this section, how many ARB offset credits that each party identified in section 95985(e)(2) must replace.

New section 95985(h)(1)(B) was added to require that the parties identified in section 95985(e)(2) must replace the ARB offset credits within six months of being notified by ARB. They must replace ARB offset credits in the amount calculated pursuant to section 95985(h)(1)(A).

New section 95985(h)(1)(C) was added to require that if the parties identified in section 95985(e)(2) do not replace the ARB offset credits within six months, each unplaced ARB offset credit is a violation.

New sections 95985(h)(1)(C)(1.) through (h)(1)(C)(3.) require that the Offset Project Operator replace the ARB offset credits in the event that the parties identified in section 95985(e)(2) are no longer in business. This will ensure that the environmental integrity of the program is preserved and the cap is made whole.

New section 95985(h)(1)(D) was added to determine which ARB offset credits will be removed from the accounts of the parties identified in section 95985(e)(2).

New section (h)(1)(E) was added to provide notice of which ARB offset credits were invalidated to the parties identified in section 95985(e)(2). New section 95985(h)(1)(F) was added to provide notice of which ARB offset credits were invalidated to programs that are linked with California's cap-and-trade program.

The invalidation requirements in original section 95985(f) were moved to new sections 95985(h)(2)(A) and (h)(2)(B). New section 95985(h)(2) adds a numbering structure to the original requirements in section 95985(f) for readability, and only addresses replacement of ARB offset credits that were invalidated for reasons identified in section 95985(c)(2) or (c)(3). The requirements were unchanged in substance, except that the parties identified in section 95985(e)(2) must replace the ARB offset credits within six months instead of 90 days. This will alleviate concerns that entities will not have enough time to find sufficient compliance instruments.

New section 95985(h)(2)(C) was added to provide notice of which ARB offset credits were invalidated to the parties identified pursuant to section 95985(e)(2). New section 95985(h)(2)(D) was added to provide notice of which ARB offset credits were invalidated to programs that are linked with California's cap-and-trade program.

Original section 95985(g) was moved to new section 95985(i). A numbering structure was added to new section 95985(i) for readability and the addition of new provisions under this section. New section 95985(i)(1) clarifies that only ARB offset credits in the Retirement Account must be replaced by the Forest Owner. New section 95985(i)(1)(A) was added to support the new provisions added in section 95985(c)(1). If ARB invalidates only a portion of the ARB offset credits from an Offset Project Data Report, ARB must determine, through the formula in this section, how many ARB offset credits that the Forest Owner must replace.

New section 95985(i)(1)(B) was added to require that the Forest Owner must replace the ARB offset credits within six months of being notified by ARB. They must replace ARB offset credits in the amount calculated pursuant to section 95985(i)(1)(A).

New section 95985(i)(1)(C) was added to require that if the Forest Owner does not replace the ARB offset credits within six months, each ARB offset credit not replaced is a violation.

New section 95985(i)(1)(D) was added to determine which ARB offset credits will be removed from the accounts of the Forest Owners.

New section 95985(i)(1)(E) was added to provide notice of which ARB offset credits were invalidated to the Forest Owner. New section 95985(i)(1)(F) was added to provide notice of which ARB offset credits were invalidated to programs that are linked with California's cap-and-trade program.

The invalidation requirements in original section 95985(g) were moved to new sections 95985(i)(2)(A) and (i)(2)(B). New section 95985(i)(2) adds a numbering structure to the original requirements in section 95985(g) for readability, and only addresses replacement of ARB offset credits that were invalidated for reasons identified in section 95985(c)(2) or (c)(3). The requirements were unchanged in substance except that the Forest Owner must replace the ARB offset credits within six months instead of 90 days. This will alleviate concerns that entities will not have enough time to find sufficient compliance instruments.

New section (i)(2)(C) was added to provide notice of which ARB offset credits were invalidated to the Forest Owner. New section 95985(i)(2)(D) was added to provide notice of which ARB offset credits were invalidated to programs that are linked with California's cap-and-trade program.

Original section 95985(h) was moved to new section 95985(j).

Also, various minor and non-substantive clarifications were made to section 95985.

67. Executive Officer Approval Requirements for Offset Project Registries (Section 95986)

New section 95986(c)(2)(A)(3.) was added to require that conflict-of-interest and confidentiality requirements be in place for any contractors of Offset Project Registries. This new section provides additional integrity to the offset program.

Section 95986(c)(2)(F) was modified to clarify that the prohibition for serving as an offset project consultant applies at the subdivision level for those applicants that have designated a subdivision to provide registry services.

Section 95986(d)(1) was modified to allow ARB to monitor for any potential conflicts of interest between an offset project registry and offset project developer who lists their offset project on the offset project registry but also contracts for other non offset project-related consulting services.

New section 95986(d)(4) was added to require that Offset Project Registries have a certain amount of knowledge in operating a registry before they may be approved. This requirement will ensure that Offset Project Registries have the demonstrated knowledge and experience necessary to perform registry services.

New section 95986(d)(5) was added to require an Offset Project Registry to have a primary business in the United States, to ensure a physical presence in the geographic region where ARB will issue offsets. This will better facilitate any in- person audits ARB may wish to pursue at the Offset Project Registry offices.

New section 95986(j) was added to ensure that the Offset Project Registry had experience in specific activities required to successfully implement an offset program.

New sections 95986(k)(5)(A) through (C) were added to require that Offset Project Registries undergo a performance review before they can be reapproved to provide registry services. These provisions were added in response to stakeholder comments that ARB should include a performance review of Offset Project Registries before reapproving them.

Original section 95986(k)(3), now section (l)(3), was modified to allow offset projects that must transfer to another registry in the event their current registry's approval is revoked to qualify for a one-year crediting period extension. These modifications were made in response to stakeholder comments that switching Offset Project Registries could cause a delay in the reporting of GHG reductions and GHG removal enhancements, and subsequently cause those reductions to be ineligible for crediting.

Also, various minor and non-substantive clarifications were made to section 95986.

68. Offset Project Registry Requirements (Section 95987)

Sections 95987(b), (g), and (h) were modified to clarify that Offset Project Registries must only make the listed information publicly available for offset projects developed under Compliance Offset Protocols. This clarification was made because the Offset Project Registries do not need to meet these requirements for offset projects that are developed for voluntary purposes.

Also, various minor and non-substantive clarifications were made to section 95987.

69. Record Retention Requirements for Offset Project Registries (Section 95988)

This section was modified to clarify that Offset Project Registries must only meet the record retention requirements for offset projects developed under Compliance Offset Protocols. This clarification was made because the Offset Project Registries do not need to meet these requirements for offset projects that are developed for voluntary purposes.

70. Recognition of Offset Credits for Early Action (Section 95990)

Section 95990(a)(2)(B) was modified to clarify that Early Action Offset Programs must only be able to track ownership and transactions for early action offset projects developed under the methodologies identified in this section. This clarification was made because the Early Action Offset Programs do not need to meet these requirements for offset projects that are developed under other protocols.

Section 95990(a)(2)(C) was modified to clarify that Early Action Offset Programs must only track early action offset credits from offset projects that qualify for early action under this section. This clarification was made because the Early Action Offset Programs do not need to meet these requirements for credits that may not be used under this article.

Section 95990(a)(3) was modified to clarify that the requirements in this provision apply to designated subdivisions, if the applicant designates a subdivision to be an Early Action Offset Program.

Section 95990(a)(3)(A) was modified to prohibit Early Action Offset Programs from acting as offset project consultants for early action offset projects registered on their own registry. This was included to prevent conflict of interest.

New section 95990(a)(3)(D) was added to require an Early Action Offset Program to have a primary business in the United States, to ensure a physical presence in the geographic region where ARB will issue early action offset credits. This will better facilitate any in-person audits ARB may wish to pursue at the Early Action Offset Program offices.

Section 95990(c)(3) was modified to change the latest date that early action offset projects can register or list their projects with an Early Action Offset Program from January 1, 2013, to January 1, 2014. This modification will allow ARB time to approve Offset Project Registries and ARB-accredited verifiers to process and verify offset projects developed under Compliance Offset Protocols.

Section 95990(c)(5) was modified to require that only the most current version of any protocol may be used at the time the project is initiated. This ensures that an early action offset project is not using an out-of-date protocol.

New sections 95990(d)(1), (e)(1)(A), and (h)(5)(A) were added to clarify that Offset Project Operators or Authorized Project Designees for forest and urban forest offset projects that do not transition their early action offset projects to Compliance Offset Protocols must register with ARB for issuance of ARB offset credits. For these projects, the holders of the early action offset credits may not register, list, meet the attestation requirements, and seek issuance of ARB offset credits. Staff is requiring the project proponents to register in these cases, to ensure that the CO_2 sequestered and credited by ARB remains sequestered, and that ARB has enforcement authority in the case of reversals from these projects.

New sections 95990(d)(2) and (d)(3), (e)(1)(B) and (e)(1)(C), and (h)(5)(B) and (h)(5)(C) were added to clarify that either the Offset Project Operator or Authorized Project Designee, or the holders of early action offset credits may: register; list; meet the attestation requirements; and seek issuance of ARB offset credits for forest or urban forest offset projects. This is contingent upon the forest or urban forest projects do transition to Compliance Offset Protocols and any offset projects developed under the methodologies listed in section 95990(c)(5)(A) and (C). Staff is allowing the holders of these credits to take actions for these early action offset projects because there is no risk of reversal for those offset projects developed under the methodologies listed in section 95990(c)(5)(A) and (C). If the forest or urban forest offset project is transitioning into the compliance offset program, ARB can monitor and address reversals in the future because the Offset Project Operator or Authorized Project Designee will be part of the compliance offset program.

New section 95990(e)(2) was modified to require that the parties identified in section 95990(e)(1) submit the required information. The structure of these provisions was changed for clarity.

Original section 95990(e)(2), now new section 95990(e)(3), was modified to require that Offset Project Registries clearly indicate which offset projects are part of the compliance offset program. This requirement was added to provide transparency.

Section 95990(f)(3)(A) was modified to require that the verifier review the Offset Verification Statement in addition to the Early Action Verification Report.

Section 95990(f)(3)(B) was modified to require that, during the desk review, the verifier review the data checks that were conducted in the original verification performed under the Early Action Offset Program. This provision was added in response to stakeholder comments to streamline the requirements for regulatory verification of Early Action Offset Credits.

Section 95990(f)(3)(C) was modified to require that the ARB accredited verifier determine with reasonable assurance whether or not they agree that a positive offset verification statement should have been issued under the Early Action Offset Program after reviewing the documentation from the original verification conducted under the Early Action Offset Program. “Reasonable assurance” is defined in the regulation. This provision was added in response to stakeholder comments to streamline the requirements for regulatory verification. Instead of issuing another verification statement, the ARB verifier must make an attestation to ARB regarding its findings.

Section 95990(f)(3)(D) was modified to support the changes in provision 95990(f)(3)(C).

Section 95990(f)(4) was modified to require that the ARB verifier recommend to ARB that full verification services be performed if the verifier cannot concur with reasonable assurance that a positive verification statement should have been issued. Staff removed the three percent or 25,000 metric ton CO_2e threshold. This provision was added in response to stakeholder comments to streamline the requirements for regulatory verification by evaluating the original verification on the threshold of five percent offset material misstatement. If the offset material misstatement was greater than five percent it would not have been issued a positive verification statement under the Early Action Offset Program. The verifier must prepare a report for ARB detailing why full verification services are warranted. ARB will make the final decision to avoid conflicts of interest in the verifier recommending the additional verification services to be performed.

New section 95990(f)(5) was added to support the modifications in section 95990(f)(4). The provision requires ARB to review the information in the report prepared by the verification body.

New section 95990(f)(6) was added to support the modifications in section 95990(f)(4). The provision requires that ARB make a final determination as to whether full verification service must be provided. If ARB finds that a positive verification statement should not have been issued, then full verification services must be performed.

New section 95990(f)(7) was added in response to stakeholder comments and to clarify the implications of a second desk review on credits that have already been transferred to ARB. This provision was included to make it clear that if a desk review has successfully been completed, no further reviews are triggered by subsequent early action verification activities for that early action offset project.

Section 95990(h)(3) was modified to support the changes made to section 95990(f)(3)(C).

New section 95990(h)(6) was modified to require that the parties identified in section 95990(h)(5) submit the required attestations. The structure of these provisions was changed for clarity. If the Offset Project Operators or Authorized Project Designees do not transfer over the early action offset projects, ARB must have parties identified as responsible for the offset credits that are brought into the system to ensure ARB's enforcement authority.

New section 95990(i)(1)(D)(1.) was added in response to stakeholder comment and to require that Early Action Offset Programs release all the credits in their buffer accounts for forest projects to ARB. This will ensure that permanence requirements are met for all early action offset projects that come over to ARB.

New section 95990(i)(1)(D)(1.)(a.) was added to clarify that credits with vintages from 2001 through 2004 that are released to ARB by the Early Action Offset Program will be given a special series of unique serial numbers and will be placed in ARB's Forest

Buffer Account. This provision is necessary so that ARB can easily identify these credits, since they may not be used in the compliance offset program.

New section 95990(i)(1)(D)(1.)(b.) was added to clarify that the credits with vintages from 2001 through 2004 that are released to ARB by the Early Action Offset Program may only be retired by ARB in the event of a reversal. It further clarifies that these vintages may not be used to satisfy ARB's Forest Buffer Account requirements under this section. This provision is necessary because these credits will still be considered voluntary credits, and not compliance offsets. ARB cannot allow voluntary credits to be used for compliance purposes. Retaining these credits in ARB's Forest Buffer Account will ensure that in the event of a reversal the atmosphere is made whole by retiring all voluntary and compliance offsets issued to the project.

Original section 95990(i)(1)(D)(2.), now new section 95990(i)(1)(D)(3.), was modified to support the changes in section 95990(i)(1)(D)(1.) and to determine how many ARB offset credits would be issued after Forest Buffer Account contributions are met, if the Offset Project Operator or Authorized Project Designee is the party that transferred the early action offset credits into the ARB system. In this case, the total number of ARB offset credits issued will be at the project level.

Original section 95990(i)(1)(D)(2.)(a.), now new section 95990(i)(1)(D)(3.)(a.), was modified to support the changes in section 95990(i)(1)(D)(1.) and describe how ARB will determine if one ARB offset credit will be issued to the Offset Project Operator or Authorized Project Designee for each early action offset credit issued to the early action forest offset project. In this case, if the total number of credits released to ARB from the buffer of the Early Action Offset Program that meets the requirements of this section is greater than or equal to the number of ARB offset credits that need to be put into ARB's Forest Buffer Account, the project will be issued one ARB offset credit for each early action offset credit, and its Forest Buffer Account contribution will be satisfied.

Original section 95990(i)(1)(D)(2.)(b.), now new section 95990(i)(1)(D)(3.)(b.), was modified to support the changes in section 95990(i)(1)(D)(1.). It describes how many ARB offset credits will be issued to the Offset Project Operator or Authorized Project Designee for each early action offset credit issued to the early action forest offset project, if the total number of credits released to ARB from the buffer of the Early Action Offset Program is less than the number of ARB offset credits that need to be put into ARB's Forest Buffer Account. Based on these factors, the Offset Project Operator or Authorized Project Designee can determine how many ARB offset credits they can be issued after satisfying the Forest Buffer Account contribution.

New section 95990(i)(1)(D)(4.) was added to support the changes in section 95990(i)(1)(D)(1.) and to determine how many ARB offset credits would be issued after Forest Buffer Account contributions are met, if the holder of the early action offset credits is the party that transferred the early action offset credits into the ARB system. In this case, the total number of ARB offset credits issued will be at the individual holder level.

New section 95990(i)(1)(D)(4.)(a.) was added to support the changes in section 95990(i)(1)(D)(1.). It describes how ARB will determine if one ARB offset credit will be issued to the holder of the early action offset credits for each early action offset credit issued to the early action forest offset project. In this case, if the total number of credits released to ARB from the buffer of the Early Action Offset Program that meets the requirements of this section is greater than or equal to the number of ARB offset credits that need to be put into ARB's Forest Buffer Account, the holder will be issued one ARB offset credit for each early action offset credit, and its Forest Buffer Account contribution will be satisfied.

New section 95990(i)(1)(D)(4.)(b.) was added to support the changes in section 95990(i)(1)(D)(1.). It describes how many ARB offset credits will be issued to the holder of the early action offset credits for each early action offset credit issued to the early action forest offset project, if the total number of credits released to ARB from the buffer of the Early Action Offset Program is less than the number of ARB offset credits that need to be put into ARB's Forest Buffer Account. Based on these factors, the holder can determine how many ARB offset credits they can be issued after it satisfies its Forest Buffer Account contribution.

Section 95990(i)(1)(E) was modified to make the calculation in this section optional. This means that the Offset Project Operator or Authorized Project Designee of the early action offset project may use this calculation to determine if it would be eligible to be issued additional ARB offset credits over and above those than it was issued under the early action offset credits criteria. If they choose not to do the calculation, they would still be issued ARB offset credits on a one-to-one basis. This provision was made optional in response to stakeholder comments that some projects may not want to go through the complicated process to be issued additional ARB offset credits.

Sections 95990(i)(1)(E)(2.), (i)(1)(E)(2.)(a.), and (i)(1)(E)(2.)(b.) were modified to provide clarity based on stakeholder comments that the text as written was unclear.

Sections 95990(j)(1) and (j)(2) were deleted and replaced with new provisions to support the changes and clarifications made to sections 95990(d), (e)(1), and (h)(5) for Offset Project Operators or Authorized Project Designees, or holders of early action offset credits.

Section 95990(k)(1) was modified to remove the requirement that early action offset projects may transition to Compliance Offset Protocols no earlier than January 1, 2013. This requirement was removed due to stakeholder comments that early action offset projects should be able to use Compliance Offset Protocols as soon as they are finalized through the rulemaking process.

Section 95990(k)(1)(D) was modified to ensure that no previously credited carbon stocks under an Early Action Offset Program would inadvertently be re-issued ARB offset credit the first year the project transitions to the Compliance Offset Protocol.

Even though the baselines would be recalculated, credit would be based on the increase in carbon stocks from the last credits issued, based on the re-calculated baseline.

Section 95990(k)(3)(C) was modified to allow GHG reductions and GHG removal enhancements that occur in 2014 under an early action protocol to be verified by September 30, 2015. This change was made in response to stakeholder comments that ARB should streamline the requirements for early action offset projects with those for offset projects using Compliance Offset Protocols by allowing early action offset projects to have nine months to verify their Early Action Data Report.

New sections 95990(l)(1) and (l)(2) were added to replace original section 95990(l). New section 95990(l)(1) provides that early action offset credits from non-sequestration offset projects may be invalidated pursuant to the relevant provisions for non-sequestration offset projects in section 95985. New section 95990(l)(1)(A) provides that if the parties identified in section 95985(e)(2) are no longer in business and the Offset Project Operator or Authorized Project Designee transitioned the early action offset credits to ARB, then the Offset Project Operator must replace the invalidated ARB offset credits. New section 95990(l)(1)(B) provides that if the parties identified in section 95985(e)(2) are no longer in business, and the holder of the early action offset credits transitioned them to ARB, then the holder that transitioned them must replace the invalidated ARB offset credits. New section 95990(l)(2) provides that early action offset credits from forest offset projects may be invalidated pursuant to the relevant provisions for forest offset projects in section 95985.

Also, various minor and non-substantive clarifications were made to section 95990.

71. Sector-Based Offset Credits (Section 95991)

No substantive changes were made to this section.

72. Procedures for Approval of Sector-Based Crediting Programs (Section 95992)

No substantive changes were made to this section.

73. Sources for Sector-Based Offset Credits (Section 95993)

No substantive changes were made to this section.

74. Requirements for Sector-Based Offset Crediting Programs (Section 95994)

No substantive changes were made to this section.

75. Quantitative Usage Limit (Section 95995)

No substantive changes were made to this section.

76. Reserved for Sector-Specific Requirements (Section 95996)

No substantive changes were made to this section.

77. Reserved for Approved Sector-Based Crediting Programs (Section 95997)

No substantive changes were made to this section.

78. Jurisdiction (Section 96010)

No substantive changes were made to this section.

79. Authority to Suspend, Revoke, or Modify (Section 96011)

Section 96011(c) was deleted because it was redundant to section 96011(a).

80. Injunctions (Section 96012)

No substantive changes were made to this section.

81. Penalties (Section 96013)

No substantive changes were made to this section.

82. Violations (Section 96014)

Section 96014(b) was modified to provide a periodic calculation for penalties. This new requirement recalculates penalties every 45 days instead of every day. The change was made in response to stakeholder concerns about large penalties accruing if the period for recalculation was every day.

83. Severability, Effect of Judicial Order (Section 96020)

No substantive changes were made to this section.

84. Confidentiality (Section 96021)

No substantive changes were made to this section.

85. Jurisdiction of California (Section 96022)

No substantive changes were made to this section.

86. Reserved Provisions (Section 96023)

No substantive changes were made to this section.

87. Modifications to Compliance Offset Protocol Urban Forest Projects

This protocol was modified to require an urban forester to be involved in the review of the project and offset project data report. The verification team must also include a forester or urban forester. These changes were necessary to ensure that the right experts were involved in the documentation preparation and review for this project type.

88. Modifications to Compliance Offset Protocol Livestock Projects

This protocol was modified to allow identical engines to share a biogas flow meter and any mention of thermocouplers for flares have been expanded to include engines. Both of these changes were in response to stakeholder comments.

The requirements for adjustments to metered biogas flow data in Section 6.1 have been replaced with a more conservative method to ensure a rigorous accounting methodology within the protocol.

Additional minor and non-substantive changes were also made to this protocol.

89. Modifications to Compliance Offset Protocol Ozone Depleting Substances Projects

This protocol was modified to include the updated leakage rates in Table 5.4. The leakage rates were updated to reflect the impacts of ARB's Refrigerant Management Program. This change had already been made to the baseline calculations, but was inadvertently left out of Table 5.4.

CFC-13 was added as an eligible gas and incorporated into the methodology based on information from U.S. EPA and others. The incorporation required changes throughout the protocol, including addition of 10-year cumulative emission rates, carbon ratios, and substitute emissions.

Additional minor and non-substantive changes were also made to this protocol.

90. Modification to Compliance Offset Protocol U.S. Forest Projects

This protocol was modified to make the definition for "Forest Owner" consistent with the cap-and-trade regulation which was modified in response to stakeholder comments.

The eligibility of offset projects was also modified to allow projects that were part of other voluntary programs to register under the Compliance Offset Protocol if the offset project owners had met legal requirements before transitioning from the other voluntary programs. Stakeholders were concerned that only projects previously registered at the Climate Action Reserve would be allowed to transition to the Compliance Offset Protocol.

Clarifications were made to the language related to projects on tribal lands.

Additional minor and non-substantive changes were also made to this protocol.

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III. SUMMARY OF COMMENTS MADE DURING THE 45-DAY COMMENT PERIOD AND AGENCY RESPONSES

Chapter III contains all comments submitted during the 45-day comment period and the subsequent Board hearing that were directed at the proposed regulation or to the procedures followed by ARB in proposing the regulation, together with ARB's responses. The 45-day comment period commenced on November 1, 2010, and ended on December 15, 2010, with additional comments submitted at the December 16, 2010, Board hearing on the proposed regulation. Comments specifically addressing the Mandatory Reporting of GHG Emissions are included and responded to in the Mandatory Reporting Regulation's (MRR) Final Statement of Reasons, which can be found on the MRR's regulatory web site (http://www.arb.ca.gov/regact/2010/ghg2010/ghg2010.htm).

We received almost 1,000 letters on the proposed regulation during the 45-day comment period, and almost 150 oral testimonies during the December 16, 2010, Board hearing. Commenters included representatives from every sector covered by the regulation (e.g., electricity, industry, and fuel distributers); community, political, and religious groups; environmental organizations; environmental justice groups; financial services providers; governmental agencies and representatives; universities and non-profit research groups; verification bodies; and many interested private parties. To facilitate ease of use, comments are categorized into one of 16 sections below, and are grouped for response wherever possible.

Table III-1 below lists commenters that submitted comments during the 45-day comment period up to and at the Board Hearing, identifies the date and form of their comments, and the Reference Code assigned to each.

A. LIST OF COMMENTERS

Table III-1: Comments Received During the 45-Day Comment Period

Abbreviation	Commenter
3DEGREES	Ian McGowan, 3Degrees Written Testimony: 12/14/2010
AAVB	Tod Delaney, Association of Accredited Verification Bodies Written Testimony: 12/9/2010
AB32IG	Shelly Sullivan, AB 32 Implementation Group Written Testimony: 12/9/2010
ABC	Josh Lieberman, American Biogas Council Written Testimony: 12/15/2010
ACC1	Cynthia Cory, Agricultural Council of California for Agricultural Council of California, Association of California Egg Farmers, California Association of Wheat Growers, California Cattlemen's Association, California Farm Bureau Federation, California Grain and Feed Association, Western Growers, Western United Dairymen Written Testimony: 12/14/2010
ACC2	Emily Rooney, Agricultural Council of California Oral Testimony: 12/16/2010
ACC3	Emily Rooney, Agricultural Council of California Written Testimony: 12/14/2010
ACKERMAN	Howard Ackerman Written Testimony: 12/10/2010
ACWA	Mark S. Rentz, Association of California Water Agencies Written Testimony: 12/15/2010
AEC	Gloria Britton, Anza Electric Cooperative Written Testimony: 12/15/2010
AEPC	Michelle Freeark, Arizona Electric Power Cooperative Written Testimony: 12/15/2010
AFFONSO	Jane Affonso Written Testimony: 12/13/2010
AFPA	Paul Noe, American Forest & Paper Association Written Testimony: 12/14/2010
AGCOALITION	Casey Creamer, Ag Coalition Written Testimony: 12/13/2010
AGECASSOC	Dan Gies, Ag Energy Consumers Association Oral Testimony: 12/16/2010
AGEE	Sharon Agee Written Testimony: 12/1/2010
AGIF1	Willie Galvan, American GI Forum Oral Testimony: 12/16/2010
AGIF2	Helen Galvan, American GI Forum Oral Testimony: 12/16/2010
ALA	Bonnie Holmes-Gen, American Lung Association Oral Testimony: 12/16/2010
ALLENAMY	Amy Allen Written Testimony: 11/24/2010

ALLENKIM	Kim Allen Written Testimony: 12/13/2010
ALLI	Dwayne Phillips, Air Liquide Large Industries U.S. LP Written Testimony: 12/15/2010
AMENTA	Annamaria Amenta Written Testimony: 12/12/2010
AMES	David Ames Written Testimony: 12/14/2010
AMOUR	Gregory Amour Written Testimony: 12/11/2010
AMSDEN	Liz Amsden Written Testimony: 12/10/2010
ANALYSISGRP	Todd Schatzki, Analysis Group Written Testimony: 12/15/2010
ANDERSONL	Laura Anderson Written Testimony: 12/10/2010
ANDREWS	Frank G. Andrews Written Testimony: 12/11/2010
ANRAFIASSOC	Tony Fisher, Anrafi Associates LLC Oral Testimony: 12/16/2010
ANSI1	Lane Hallenbeck, American National Standards Institute Written Testimony: 12/9/2010
ANSI2	Lane Hallenbeck, American National Standards Institute Oral Testimony: 12/16/2010
APC	Keith Adams, P.E., Air Products and Chemicals Written Testimony: 12/15/2010
ARNDT	Celestine Arndt Written Testimony: 12/10/2010
ARTENO	Ron Arteno Written Testimony: 12/10/2010
ASMDICKINSON	Roger Dickinson, California State Assembly Written Testimony: 12/15/10
ASMMANDEVORE1	Chuck DeVore, California State Assembly Written Testimony: 12/15/2010
ASMMANDEVORE2	Chuck DeVore, California State Assembly Written Testimony: 12/15/2010
ASMMANDEVORE3	Chuck DeVore, California State Assembly Written Testimony: 12/15/2010
ASMMANDEVORE4	Chuck DeVore, California State Assembly Written Testimony: 12/15/2010
ASMSKINNER	Nancy Skinner, California State Assembly Written Testimony: 12/15/2010
ATAA	Kevin Welsh, Air Transport Association of America Written Testimony: 12/15/2010
ATCHER	Sheila Atcher Written Testimony: 12/15/2010
ATP	Greg Fisher, Auburn Tea Party Written Testimony: 11/30/2010
AVW	Kurt Schoeneman, Anderson Valley Winegrowers Written Testimony: 12/9/2010

AWSINC	James Brady, Con10U Written Testimony: 12/16/10
AYERS	Gordon Ayers Written Testimony: 12/1/2010
BAAQMD	Brian Bateman, Bay Area Air Quality Management District Oral Testimony: 12/16/2010
BAAQMD2	Jack Broadbent, Bay Area Air Quality Management District Written Testimony: 12/08/2010
BABIGIAN	Walter Babigian Written Testimony: 11/30/2010
BACWAAC	James Sandoval, Bay Area Clean Water Agencies Air Issues and Regulations Committee Written Testimony: 12/15/2010
BALL	Molly Ball Written Testimony: 12/1/2010
BAPATRIOTS	Diane Richards, Bay Area Patriots Written Testimony: 12/12/2010
BARKOW	Carolyn Barkow Written Testimony: 12/14/2010
BARRICK	Marcel Barrick Written Testimony: 12/10/2010
BATTLECREEK1	Susan Robinson, Battle Creek Alliance; Marily Woodhouse, Battle Creek Alliance; Robin Huffman, Butte Environmental Council; Greg Suba, California Native Plant Society; Patty Clary, Californians Against Toxics; Sue Lynn, Cascade Action Now!; Brian Nowicki, Center for Biological Diversity; Jodi Frediani, Central Coast Forest Watch; Barry Boulton, Central Sierra Audubon Society; John Buckley, Central Sierra Environmental Resource Center; Karen Schambach, Center for Sierra Nevada Conservation; Joseph Bower, Citizens for Better Forestry; Denise Boggs, Conservation Congress; Kim Delfino, Defenders of Wildlife; Susan Robinson, Ebbetts Pass Forest Watch; Terry O'Day, Environment Now; Scott Greacen, Environmental Protection Information Center; Mark Rockwell, Northern California Federation of Fly Fishers; Chris Wright, Foothill Conservancy; Todd Paglia, Forest Ethics; Luke Breit, Forests Forever; Don Rivenes, Forest Issues Group; Rick Coates, Forest Unlimited; Laurie Davis, Friends of Lassen Forest; Kate Horner, Friends of the Earth; Nadananda, Friends of the Eel River; Mauro Oliveira, Geoengineering Watch; Rolf Skar, Greenpeace; Chad Hanson, John Muir Project; Kimberly Baker, Klamath Forest Alliance; Patricia Puterbaugh, Lassen Forest Preservation Group; Jeff Kuyper, Los Padres ForestWatch; Bob Kelso, Mountain Alliance; Steve Robinson, Mountain Meadows Conservancy; Pete Nichols, Northcoast Environment Center; Larry Hanson, Northern California River Watch; Traci Sheehan, Planning and Conservation League; Bill Barclay, Rainforest Action Network; Fred Krueger, Religious Campaign for Forest Conservation; Ara Marderosian, Sequoia ForestKeeper; Michael Endicott, Sierra Club California; Shera Blume, Sierra People's Forest Service; Kevin Collins, Lompico Watershed Conservancy; Steven Evans, Friends of the River; Larry Glass, Safe

	Alternative for our Forest Environment; Craig Thomas, Sierra Forest Legacy; Joan Clayburgh, Sierra Nevada Alliance; Greg King, Siskiyou Land Conservancy; Mauro Oliveira, StopClearcutting California; Robert Dean, Upper Mokelumne River Watershed Council; Warren Linney, World Stewardship Institute Written Testimony: 12/13/10
BATTLECREEK2	Susan Robinson, Battle Creek Alliance Oral Testimony: 12/16/2010
BCFSE	Lisa Jacobson, Business Council for Sustainable Energy Written Testimony: 12/15/2010
BEAVER	Melissa Beaver Written Testimony: 12/14/2010
BEAZLIE	Janet Beazlie Written Testimony: 12/13/2010
BECKER	Carol Becker Written Testimony: 12/10/2010
BEDECARRE	John Bedecarre Written Testimony: 12/10/2010
BEILEY	Michael Beiley Written Testimony: 12/2/2010
BELLOVICH	Carl Bellovich Written Testimony: 12/15/2010
BENSON	Norm Benson Written Testimony: 12/15/2010
BERALL	Elissa Berall Written Testimony: 12/10/2010
BEVINGTON	Doug Bevington, Environment Now Oral Testimony: 12/16/2010
BFFP	George Gentry, Board of Forestry and Fire Protection Written Testimony: 12/15/10
BILLER	James Biller Written Testimony: 12/12/2010
BILLIA	Richard Billia Written Testimony: 11/30/2010
BIRDLEBOUGH	Steve Birdlebough Written Testimony: 11/17/2010
BITHELL	Marianne Bithell Written Testimony: 11/22/2010
BJELLE	LeAnn Bjelle Written Testimony: 12/10/2010
BLACK	Edith Black Written Testimony: 12/13/2010
BLAKEMORE	Lee Blakemore Written Testimony: 12/9/2010
BLUESOURCE	Roger Williams, Blue Source Written Testimony: 12/13/2010
BMWGROUP	Andreas Klugescheid, BMW Group Written Testimony: 12/15/2010

BODEGRAVEL	John Ward, Bode Gravel Company; Central Concrete Supply; Central Valley Concrete; Enviro-Crete Inc.; Folsom Ready Mix; Graniterock Company; Knife River Corporation; Outback Materials; Right Away Redy Mix; Shamrock Materials; Syar Concrete LLC; Teichert Materials Written Testimony: 12/14/2010
BOGGS	Coy Boggs Written Testimony: 12/1/2010
BOGIOS	Constantine Bogios Written Testimony: 12/13/2010
BONASERA	Rita Bonasera Written Testimony: 12/14/2010
BONNEVILLEPWR	Courtney Olive, Bonneville Power Administration Written Testimony: 12/15/2010
BOOZ	Martha Booz Written Testimony: 12/9/2010
BOREAN	Les Borean Written Testimony: 12/10/2010
BOSWELL	Garry Boswell Written Testimony: 12/1/2010
BOWLES	Donald Bowles Written Testimony: 12/14/2010
BOYDC	Christine Boyd Written Testimony: 12/11/2010
BP	Ralph Moran, BP America Inc. Written Testimony: 12/10/2010
BRATCHER	Suzanne Bratcher Written Testimony: 12/14/2010
BRAXTON	Cook Braxton Written Testimony: 12/10/2010
BRENNAN	Robert Brennan Written Testimony: 12/9/2010
BROCKMAN	John Brockman Written Testimony: 12/10/2010
BROESAMLE	Don Broesamle Written Testimony: 12/6/2010
BROOKS	Connie Brooks Written Testimony: 11/30/2010
BROWNE	Kelly Browne Written Testimony: 12/14/2010
BROWNRE	Rebecca Brown Written Testimony: 12/14/2010
BROWNRI	Rick Brown Written Testimony: 12/14/2010
BROWNRO	Roger Brown Written Testimony: 12/10/2010
BROWNT	Thomas Brown Written Testimony: 11/30/2010
BRUEGEMAN	Donald Bruegeman Written Testimony: 11/30/2010

BRYANT	Chester Bryant Written Testimony: 12/14/2010
BTINC	Guy Drouin and Raphael Bruneau, Biothermica Technologies Inc. Written Testimony: 11/25/2010
BUI	Khoi Bui Written Testimony: 12/10/2010
BULGER	Debbie Bulger Written Testimony: 11/22/2010
BURCH	Kelly Burch Written Testimony: 12/10/2010
BURDINE	Janine Burdine Written Testimony: 12/11/2010
BURKS	Paul Burks Written Testimony: 12/13/2010
BUSH	Steve Bush Written Testimony: 12/14/2010
BUSSE	Richard Busse Written Testimony: 12/14/2010
CABAGE1	Susan Frank, California Business Alliance for a Green Economy; Ian McGowan, 3Degrees; Steve Kirsch, Abaca; Mark Marovich, A Barn Collective; Ann Hewitt, Anacapa Consulting Servcies Inc.; Thomas O'Brien, Apollo Energy Systems; Todd Pitcher, Aspire CleanTech Communications; Michael Vargas, Atlas Project Support; Elaine Rubin & Arthur Rubin, Authors & Editors; Andreas Wittenstein, Bit Jazz Inc.; Leslie Berliant, BLU MOON Group; Mary Sue Milliken & Susan Feniger, Border Grill; Tom Bowman, Bowman Design Group; Beth Gelfand, The Buddy Club Children's Shows; Dan Thomsen, Building Doctors Inc.; Emir Jose Macari, California Smart Grid Center; Bob Roberts, California Ski Industry Association; Lesli Katz, Champion Telecom; Christ Klich, The Chris Klich Jazz Quintet; Don Christiansen, Christiansen Consulting; James Birkelund, Cleantech Law Partners; Warren Smith, CleanWorld Partners; Katherine Forrest, Commonweal Institute; Kathleen Connell, Connell Whittaker Group, LLC; Christina Schwerdtfeger, Coto Consulting; Peter Zahn, Counsel Direct Law Offices; Tom Soto, Craton Equity Partners; Joe Cuviello, Cuviello Agency; Yeves Perez, EcoHub, Inc.; Lee Bruno, E-Cubed Ventures, LLC; Hank Ryan, Efficiency Data & Development; Ricardo Bayon, EKO Asset Management Partners, LLC; Lary Heath, Enluma; Holly Kaufman, Environment & Enterprise Strategies; Mark Quigley, Environmental Builders, Inc.; Joe Madden, EOS Climate, Inc.; Greg Watkins, Equinox Carbon Development Corporation; Dan Walden, Forester Media, Inc.; Julia Brown, Forestview Advisors; Ted Kniesche, Fulcrum BioEnergy Inc.; Gi Paoletti, Gi Paoletti Design Lab; Glen Dake, Glen Dake Landscape Architect; Craig Flax, Good Things Green Inc.; Carol McClettand, Green Career Central; Janet Pomeroy, Green Chamber of Commerce; David Steel, Green Chamber of Commerce of San Diego County;

	Courtland Weisieder, Greener Dawn Inc.; Steve Lehtonen, GreenPlumbers USA; Richard Nozz, GreenVision for Business Inc.; Selim Sandoval, Growing Green Energy; Don Dotter, Grupio; Shelly Dale, Hair West Salon; Carroll Harrington, Harrington Design; Shelley Kramer, Healthy Homes, Healthy Bodies; Kenneth Collins, High Desert Region Green Jobs Initiative; David Herrlinger, Hot Purple Energy; Ricki Becker, IMPACT Printing & Advertising; Danial Emmett, Innovo Energy Solutions Group; Melissa Michaels, Inpeloto LLC; David Rosenstein, Intex Solutions; Dave Rosenheim, JamBase Inc.; Jonathan Landworth, J. Landworth Company; John D. Kelley, John D. Kelley Architectural Services; Julie Dunn, Julie Dunn Fine Art; Alex Kahl, Kahl Consultants; John Ross, Keoni Landscapes; Mark Riddlesperger, LA Pro Point Inc.; Shawn Alvandi, LA Solar Systems Inc.; Jennifer Berg, Law Offices of Jennifer K. Berg; Jon Lentz, Lentz Group Global; Rebecca Tarver, Lotus Cleaning Services; Gabriel Romero, Love & Light, Inc.; Donny Vasquez, Made in the Shade Tent Rentals Inc.; Arthur Keller, Minerva Consulting; Chuck Mirjahangir, Mirjahangir Engineering; Paul Mudge, Mudge Fasteners Inc.; Jon Slangerup, N.E.I. Treatment Systems; Stephen Bjorgan, NetZero Energy LLC; Marisa Meizlish, New Forests Advisory Inc.; Elliot Hoffman, New Voice of Business; Michael Hetz, The Noodle Shop; Jacqueline Keller, NutriFit LLC/ SimpliHealth Growers; Michael Stocker, Ocean Conservation Research; Edith Ogella, Ogella Family Day Care; Eric Freed, organicARCHITECT; Riggs Echelberry, OriginOil Inc.; Don Wood, Pacific Energy Policy Center; Paula Sandas, Palo Altho Chamber of Commerce; Joia Gibble, PermaCity Solar Inc./Perma city Construction Corp.; Jim Petersen, PetersenDean Inc.; Scott Sibley, Photo International; Jonty Pretzer, Pretzer Green Consulting; JoAnn Armenta, Purpose Focused Alternative Learning Corp.; Arno Harris, Recurrent Energy; Tammy Schwolsky, Residential Energy Assessment Services; Jim Jenal, Run on Sun; Phil Salomone, Salomone Construction; Rob Black, San Francisco Chamber of Commerce; Ken Haggard, San Luis Sustainability Group; Susan Rigali, Savor Solar Catering; Dave Meyer, SEEDS Global Alliance; Tim Sexton, The Sexton Company; Stefanie Haering, SH Design Studio; Steven Frisch, Sierra Business Council; Sid Abama, Sidel Systems USA Inc.; Scott Sporrer, Siliken USA; Randal Grow, Simbol Materials; Scott Hauge, Small Business California; John Arensmeyer, Small Business Majority; Christine Herzog, Smart Grid Library; Lane Sharman, Solana Energy; Meghan Nutting, SolarCity; David Hochschild, Solaria; Mike Anderson, Solar Power Inc.; Doug Payne, SolarTech; Thomas Ackerman, Spirit Graphics & Printing; Kathy Nolan, Studio Landscape Corp.; Mark McLeod, Sustainable Business Alliance; Kuldip Sethi, SV Green Tech Corp.; Pete Micklish, Tegrus Builders Inc.; Erin Craig, TerraPass; Sandra Stewart, Thinkshift Communications; Ashleigh Talbert, U.S. Green Building Council, Northern CA Chapter; Liz Merry, Verve Consulting; Alia

	Khidiatove, West Coast Limousine Inc.; Arthur Rubin, The Wise Advisor; Eben Brooks, Working Class Superhero Productions; Monica Niess, The Write Choice Network; Shelly Mazer, Zebra Entertainment and Events Written Testimony: 12/15/10
CABAGE2	Susan Frank, California Business Alliance for a Green Economy Oral Testimony: 12/16/2010
CACAN1	Jeanne Merrill, California Climate and Agricultural Network; Brett Melone, Agriculture & Land-Based Training Association; Claudia Reid, California Certified Organic Farmers; Rebecca West, Center for Food Safety; David Runsten, Community Allian with Family Farmers; Russ Lester, Dixon Ridge Farms; Whitney Muse, Earthbound Farm; Poppy Davis, Ecological Farming Association; Judith Redmond, Full Belly Farm; John Anderson, Hedgerow Farms; Helge Hellberg, Marin Organic; Rex Dufour, National Center for Appropriate Technology; Dave Henson, Occidental Arts & Ecology Center; Ariane Lotti, Organic Farming Research Foundation; Sibella Kraus, SAGE; JoAnn Baumgartner, Wild Farm Alliance Written Testimony: 12/15/10
CACAN2	Jeanne Merrill, California Climate and Agriculture Network Oral Testimony: 12/16/2010
CACC	Beth Vaughan, California Cogeneration Council Written Testimony: 12/9/2010
CACDGC	Eric Wong, California Clean DG Coalition Written Testimony: 12/15/2010
CADMANL	Lynne Cadman Written Testimony: 12/10/2010
CADMANS	Susan Cadman Written Testimony: 12/10/2010
CAEEIC	Steve Schiller, California Energy Efficiency Industry Council Oral Testimony: 12/16/2010
CAEJA	Strela Cervas, California Environmental Justice Alliance Oral Testimony: 12/16/2010
CAFORESTRYASSOC1	David A. Bischel, California Forestry Association Written Testimony: 12/15/10
CAFORESTRYASSOC2	David A. Bischel, California Forestry Association Oral Testimony: 12/16/2010
CAHCPCOALITION	John Hopkins, California Habitat Conservation Planning Coalition Written Testimony: 12/15/2010
CAHISPCMBR	Julian Canete, California Hispanic Chambers of Commerce Oral Testimony: 12/16/2010
CALCHAMBER1	Brenda Coleman, CalChamber Written Testimony: 12/15/2010
CALCHAMBER2	Robert Callahan, CalChamber Oral Testimony: 12/16/2010
CALDERWOOD	Anne Calderwood Written Testimony: 12/11/2010
CALENERGY	Stephen Larsen, CalEnergy Operating Corporation Written Testimony: 12/15/2010

CALERACORP	Thomas Carter, Calera Corporation Written Testimony: 12/15/2010
CALFP1	John Larrea, California League of Food Processors Written Testimony: 12/14/2010
CALFP2	John Larrea, California League of Food Processors Oral Testimony: 12/16/2010
CALLAWAY	Merita Callaway, Calaveras County Supervisor Written Testimony: 12/15/10
CALPINE1	Kassandra Gough, Calpine Corporation Written Testimony: 12/9/2010
CALPINE2	Kassandra Gough, Calpine Corporation Oral Testimony: 12/16/2010
CALSEIA	Sue Kateley, California Solar Energy Industries Association Written Testimony: 12/15/2010
CAMPO	Joanne Campo Written Testimony: 11/30/2010
CAMPRINI	Janet Camprini Written Testimony: 12/2/2010
CANAACP	Malaki Amen, California National Association for the Advancement of Colored People Oral Testimony: 12/16/2010
CANFIELD1	John Canfield Written Testimony: 12/12/2010
CANFIELD2	John Canfield Oral Testimony: 12/16/2010
CANNON	Michael Cannon Written Testimony: 12/13/2010
CANTORCO2E	Josh Margolis, CantorCO2e Written Testimony: 12/15/2010
CAPCOA1	Thomas Christofk, California Air Pollution Control Officers Association Written Testimony: 12/8/2010
CAPCOA2	Larry Greene, California Air Pollution Control Officers Association Oral Testimony: 12/16/2010
CAR1	Gary Gero, Climate Action Reserve Written Testimony: 12/14/2010
CAR2	Joel Levin, Climate Action Reserve Oral Testimony: 12/16/2010
CAR3	Gary Gero, Climate Action Reserve Oral Testimony: 12/16/2010
CARBONSHARE	Mike Sandler, Carbon Share Written Testimony: 12/9/2010
CARELEAF	Joe Liszewski, California ReLeaf Written Testimony: 12/16/10
CARLONE	Tania Carlone, Yuba Watershed Institute Written Testimony: 12/14/2010
CARLTON	Alan Carlton Written Testimony: 11/18/2010
CARMICHAEL	Victor Carmichael Written Testimony: 12/15/2010

CARNAHAN	Walter Carnahan Written Testimony: 12/14/2010
CARRILLO	Joshua Carrillo Written Testimony: 12/6/2010
CASCADEACTION	Sue Lynn, Cascade Action Now Oral Testimony: 12/16/2010
CASEY	Gloriana Casey Written Testimony: 12/10/2010
CASPARINST	Michael Potts, Caspar Institute Written Testimony: 12/11/2010
CASTLEREY	Christina Castle Rey Written Testimony: 12/13/2010
CATHCHAR1	Elvira Ramirez, Catholic Charities Written Testimony: 12/14/2010
CATHCHAR2	Betsy Reifsnider, Catholic Charities; Stockton Diocese; California Interfaith Power and Light Oral Testimony: 12/16/2010
CATRANSASSOC1	Joshua Shaw, California Transit Association Written Testimony: 12/13/2010
CATRANSASSOC2	Sabrina Means, California Transit Association Oral Testimony: 12/16/2010
CATTIVA	Serena Cattiva Written Testimony: 12/14/2010
CAWWCCG1	Jacqueline Kepke, California Wastewater Climate Change Group Written Testimony: 12/15/2010
CAWWCCG2	Jacqueline Kepke, California Wastewater Climate Change Group Oral Testimony: 12/16/2010
CBD1	Brian Nowicki and Kevin Bundy, Center for Biological Diversity Written Testimony: 12/15/2010 **In addition, 46 supplemental documents were submitted**
CBD3	Brian Nowicki, Center for Biological Diversity Oral Testimony: 12/16/2010
CBE1	Adrienne Bloch, Communities for a Better Environment Written Testimony: 12/14/2010 **In addition, 11 supplemental documents were submitted**
CBEA1	Julee Malinowski-Ball, California Biomass Energy Alliance Written Testimony: 12/15/10
CBEA2	Julee Malinowski-Ball, California Biomass Energy Alliance Oral Testimony: 12/16/2010
CCA1	Nidia Bautista and Shankar Prasad, Coalition for Clean Air Written Testimony: 12/10/2010
CCA2	Nidia Bautista, Coalition for Clean Air Written Testimony: 12/15/2010
CCA3	Shankar Prasad, Coalition for Clean Air Oral Testimony: 12/16/2010
CCA4	Nidia Bautista, Coalition for Clean Air Oral Testimony: 12/16/2010
CCAP1	Ann Chan, Center for Clean Air Policy Written Testimony: 12/10/2010

CCAP2	Ann Chan, Center for Clean Air Policy Oral Testimony: 12/16/2010
CCASSOC	Justin Oldfield, California Cattleman's Association Oral Testimony: 12/16/2010
CCC	Robert Wyman, California Climate Coalition Written Testimony: 12/14/2010
CCCSD	James Kelly, Central Contra Costa Sanitary District Written Testimony: 12/15/2010
CCEEB1	Robert W. Lucas and Gerald D. Secundy, California Council for Environmental and Economic Balance Written Testimony: 12/15/2010
CCEEB2	Mik Skvaria, California Council for Environmental and Economic Balance Oral Testimony: 12/16/2010
CCGG	Casey Creamer, California Cotton Ginners and Growers Associations; Wester Agriculture Processors Associations Oral Testimony: 12/16/2010
CE2CP	Gregory Arnold, CE2 Capital Partners Written Testimony: 12/15/2010
CEEIC	Steven Schiller, California Energy Efficiency Industry Council Written Testimony: 12/14/2010
CEERT	Danielle Osborne Mills, Center For Energy Efficiency And Renewable Technologies Oral Testimony: 12/16/2010
CEP	David Rubenstein, California Ethanol Power Written Testimony: 12/7/2010
CERELLO	Robert Cerello Written Testimony: 12/10/2010
CERP1	Kyle Danish and Megan Ceronsky, Coalition for Emission Reduction Project Written Testimony: 12/6/2010
CERP2	Megan Ceronsky and Kyle Danish, Coalition for Emission Reduction Projects Written Testimony: 12/9/2010
CERP3	Megan Ceronsky, Coalition for Emission Reduction Projects Oral Testimony: 12/16/2010
CFA	David A. Bischel, California Forestry Association Written Testimony: 12/9/2010
CHABAN	Joel Chaban Written Testimony: 12/9/2010
CHAVEZ	Charlotte Chavez Written Testimony: 12/9/2010
CHEVRON1	Steve Burns, Chevron Written Testimony: 12/15/2010
CHEVRON2	Julia Bussey, Chevron Oral Testimony: 12/16/2010
CHITTENDEN	David and Claudia Chittenden Written Testimony: 12/9/2010
CHRISR	Chris R. Written Testimony: 12/1/2010

CHRISTJANER	Karey Christ-Janer Written Testimony: 12/15/2010
CHRZANOWSKI	Austin Chrzanowski Written Testimony: 12/14/2010
CHUNG	Helena Chung Written Testimony: 12/14/2010
CIBILICH	Jerry Cibilich Written Testimony: 12/11/2010
CIG	Charles Purshouse, Camco International Group, Inc. Written Testimony: 12/8/2010
CIPAL	Susan Stephenson, California Interfaith Power and Light Written Testimony: 12/14/2010
CITYRIVERSIDE	David Wright, City of Riverside Oral Testimony: 12/16/2010
CLCV	Rita Kern, California League of Conservation Voters Written Testimony: 12/11/2010
CLIMATEWEDGE	Alex Rau, Climate Wedge Ltd. Written Testimony: 12/15/2010
CMTA1	Dorothy Rothrock, California Manufacturers and Technology Association Written Testimony: 12/9/2010
CMTA2	Dorothy Rothrock, California Manufacturers and Technology Association Oral Testimony: 12/16/2010
CMUA1	David Modisette, California Municipal Utilities Association Written Testimony: 12/8/2010
CMUA2	David Modisette, California Municipal Utilities Association Oral Testimony: 12/16/2010
CMWEBER	Denis Weber Written Testimony: 12/13/2010
COCLRAN	Karen Coclran Written Testimony: 12/7/2010
CODEXIS	Alan Shaw, CODEXIS Written Testimony: 12/15/2010
COEU1	Eric Eisenhammer, Coalition of Energy Users Written Testimony: 12/14/2010
COEU2	Eric Eisenhammer, Coalition of Energy Users Oral Testimony: 12/16/2010
COHEN1	Marvin Cohen Written Testimony: 12/10/2010
COHEN2	Ellie Cohen Written Testimony: 12/13/2010
COLBY	Mark Colby Written Testimony: 12/11/2010
COLE	Chris Cole Written Testimony: 12/2/2010
COMMONS	Sandy Commons Written Testimony: 12/13/2010
COMPTON	Randy Compton Oral Testimony: 12/16/2010

CONNERS	Dan Conners Written Testimony: 12/14/2010
CONOCO	Jay D. Churchill for L.M. Ziemba, ConocoPhillips Company Written Testimony: 12/16/2010
CONSTELLATIONENERGY	Paul J. Allen, Constellation Energy Written Testimony: 12/15/2010
CONSUMERSUNION	Shannon Baker-Branstetter, Consumers Union Written Testimony: 12/15/2010
COOKINHAM	Dennis Cookinham Written Testimony: 12/12/2010
COOPERKEIL	Lisa Cooper-Keil Written Testimony: 12/10/2010
COPC1	Roger Williams, Carbon Offset Providers Coalition Written Testimony: 12/14/2010
COPC2	Nicho Van Aelstyn, Carbon Offset Providers Coalition Oral Testimony: 12/16/2010
CORNERHOUSE	Larry Lohmann, The Corner House Written Testimony: 12/15/2010
CORREIA	John Correia Written Testimony: 11/30/2010
COYLE	Daniel Coyle Written Testimony: 11/30/2010
CPC1	Ann Hancock, Climate Protection Campaign Written Testimony: 12/6/2010
CPC2	Woody Hastings, Climate Protection Campaign Written Testimony: 12/14/2010
CPC3	Pete Gang, Climate Protection Campaign Oral Testimony: 12/16/2010
CPC4	Barry Vesser, Climate Protection Campaign Oral Testimony: 12/16/2010
CPC5	Rafael Aguilera, Climate Protection Campaign Oral Testimony: 12/16/2010
CPKELCO	Ron Halik, CP Kelco Written Testimony: 12/15/2010
CRANFIELD	D. Cranfield Written Testimony: 12/11/2010
CRAWFORD	Theodora B. Crawford Written Testimony: 12/12/2010
CREA	Joe Aguilar, Commerce Refuse-to-Energy AuthorityWritten Testimony: 12/14/2010
CREDOACTION	Adam Quinn, CREDO Action Oral Testimony: 12/16/2010
CREW	Aaron Crew Written Testimony: 12/2/2010
CRI	Kirk Marckwald, California Railroad Industry Written Testimony: 12/15/2010
CROOKS	Robert Crooks Written Testimony: 11/30/2010
CROULET	Paul Croulet Written Testimony: 11/30/2010

CRPE1	Sofia Parino, Center on Race, Poverty and the Environment; Tom Frantz, Association of Irritated Residents; Penny Newman, The Center for Community Action and Environmental Justice; Teresa DeAnda, El Comite para el Bienestar de Earlimart; Martha Guzman Aceves, California Rural Legal Assistance Foundation; Anna Yun Lee, Communities for a Better Environment; Jane Williams, California Communities Against Toxics; Nicole Capretz, Environmental Health Coalition Written Testimony: 12/14/2010
CRPE2	Caroline Farrell, Center on Race, Poverty and the Environment Oral Testimony: 12/16/2010
CRPE3	Laura Baker, Center on Race, Poverty and the Environment Oral Testimony: 12/16/2010
CRS	Jennifer Martin, Center for Resource Solutions Written Testimony: 12/14/2010
CRUMP	Ellen Crump Written Testimony: 12/11/2010
CRUPI	Kevin Crupi Written Testimony: 12/9/2010
CRUTCHER	Randy Crutcher Written Testimony: 12/1/2010
CSCME2	Stephen Orava, Coalition for Sustainable Cement Manufacturing and Environment Written Testimony: 12/15/2010
CSCME3	John Bloom, Coalition for Sustainable Cement Manufacturing and Environment Oral Testimony: 12/16/2010
CSS	Sharon Banks, Cascade Sierra Solutions Written Testimony: 12/16/10
CSUF	Wendell Hovey Written Testimony: 12/10/2010
CTA	Eric Sauer, California Trucking Association Written Testimony: 12/14/2010
CTW	Nicholas Buxton and Oscar Reyes, Carbon Trade Watch Written Testimony: 12/15/2010
CUNNINGHAM	Gerry Cunningham Written Testimony: 12/11/2010
CURTIS	Bradley Curtis Written Testimony: 12/14/2010
CVAQC	Catherine White, Central Valley Air Quality Coalition; Emily Schrepf, National Parks Conservation Association; Sarah Sharpe, Fresno Metro Ministry Written Testimony: 12/14/10
CVTP	Kalyn Hill, Central Valley Tea Party Written Testimony: 12/10/2010
DANIELSE	Edith Daniels Written Testimony: 12/8/2010
DANIELSL	Lynda Daniels Written Testimony: 12/10/2010

DAUKSCH	Kelly Dauksch Written Testimony: 11/30/2010
DAVISSTEIN	Jessica Davis-Stein Written Testimony: 12/15/2010
DAWID	Irvin Dawid Written Testimony: 12/9/2010
DECKER	Barbara Decker Written Testimony: 12/14/2010
DEDEKA	Jan De Deka Written Testimony: 12/14/2010
DELACRUZ	Juan de la Cruz Oral Testimony: 12/16/2010
DELATTE	M. Delatte Written Testimony: 12/11/2010
DENNIS	John Dennis Written Testimony: 12/14/2010
DFFP1	Bill Snyder, Department of Forestry and Fire Protection Written Testimony: 12/15/10
DFFP2	Bill Snyder, Department of Forestry and Fire Protection Oral Testimony: 12/16/2010
DIAMOND	Mitchell Diamond Written Testimony: 12/10/2010
DILLER	Timothy Diller Written Testimony: 12/9/2010
DISENHOUSE	Masada Disenhouse Written Testimony: 12/14/2010
DITMORE	Alan Ditmore Written Testimony: 12/9/2010
DMF	Jim Mortensen, Del Monte Foods Oral Testimony: 12/16/2010
DONOVAN	Charlotte Donovan Written Testimony: 12/10/2010
DOWCHEM1	Dale Backlund, Dow Chemical Company Written Testimony: 12/13/2010
DOWCHEM2	Dale Backlund, Dow Chemical Company Written Testimony: 12/16/10
DOWCHEM3	Dale Backlund, Dow Chemical Company Oral Testimony: 12/16/2010
DRA	Dave Ashuckian, Division of Ratepayer Advocates Written Testimony: 12/9/2010
DSOUZA	Gladwyn D'souza Written Testimony: 12/14/2010
DULLEA	Patrick Dullea Written Testimony: 12/4/2010
DUNGAN	Joe Dungan Written Testimony: 12/2/2010
DURKEE	Kay Durkee Written Testimony: 12/1/2010
DUTTON	Elizabeth Dutton Written Testimony: 12/10/2010

DWR	Veronica Hicks, California Department of Water Resources Written Testimony: 12/15/2010
EARHART	Anne Earhart Written Testimony: 12/10/2010
EARLE	Ted Earle Written Testimony: 12/14/2010
EASTMAN	Gary Eastman Written Testimony: 12/2/2010
EBCHR	Evelyn Rangel-Medina, Ella Baker Center for Human Rights Oral Testimony: 12/16/2010
EBERHARD	Kristin Eberhard, Natural Resources Defense Council; Erin Rogers, Union of Concerned Scientists; James Fine, Environmental Defense Fund; Bill Magavern, Sierra Club California Written Testimony: 12/6/2010
EDF1	James Fine, Environmental Defense Fund Written Testimony: 12/13/2010 **In addition, 1 supplemental document was submitted**
EDF2	James Fine, Environmental Defense Fund Oral Testimony: 12/16/2010
EDF3	Tim O'Connor, Environmental Defense Fund Oral Testimony: 12/16/2010
EDIRISINGHE	Supun Edirisinghe Written Testimony: 12/9/2010
EICHELBERGER	John Eichelberger Written Testimony: 12/11/2010
EIN	Tyson Eckerle, Energy Independence Now Written Testimony: 12/15/2010
ELIAS1	Steve Elias Written Testimony: 12/8/2010
ELIAS2	Steve Elias Oral Testimony: 12/16/2010
EMWD	Anthony J. Pack, Eastern Municipal Water District Written Testimony: 12/15/2010
ENDICOTT	Marisa Endicott Written Testimony: 11/20/2010
ENEVOLDSEN	David Enevoldsen, Written Testimony: 12/13/2010
ENP	Jack Pouchet, Emerson Network Power Written Testimony: 12/10/2010
ENVDEVELOPERS	Herman Miller, Environmental Developers Inc. Written Testimony: 12/11/2010 **In addition, 1 supplemental document was submitted**
ENVENTREP1	Diane Doucette and Tony Bernhardt, Environmental Entrepreneurs Written Testimony: 12/13/2010
ENVENTREP2	Tony Bernhardt, Environmental Entrepreneurs Oral Testimony: 12/16/2010
EOSC1	Jeff Cohen, EOS Climate Written Testimony: 12/3/2010

EOSC2	Jeff Cohen, EOS Climate Oral Testimony: 12/16/2010
EPFW1	Rhoda Nussbaum, Ebbets Pass Forest Watch Written Testimony: 12/3/2010
EPFW2	Patricia Sarvis, Ebbetts Pass Forest Watch Written Testimony: 12/11/2010
EPUC	Evelyn Kahl, Energy Producers and Users Coalition Written Testimony: 11/19/2010
EQUATOR	Jessica Orrego, Equator LLC Written Testimony: 12/15/2010
ERICKSON	Brent Erickson, Biotechnology Industry Organization Written Testimony: 12/15/10
ERILANE	Carol Erilane Written Testimony: 12/9/2010
ESSERMAN	Chuck Esserman Written Testimony: 12/3/2010
EVMKTS	Lenny Hochschild, Evolution Markets Inc. Written Testimony: 12/14/2010
FARLY	Pam Farly Written Testimony: 12/15/2010
FAULKNER	Henry Faulkner Written Testimony: 12/12/2010
FCC	Greg Arnold, CE2 Capital Partners, LLC; Chandler Van Voorhis, C2I, LLC; Roger Williams, Blue Source LLC; Eron Bloomgarten, Equator, LLC Written Testimony: 12/13/2010
FEICHTL	James Feichtl, Denise Minter, and Elizabeth Gunston Written Testimony: 11/27/2010
FELLER1	Tim Feller Written Testimony: 12/16/10
FELLER2	Tim Feller Oral Testimony: 12/16/2010
FERNWOOD	Mark Fernwood Written Testimony: 12/7/2010
FESSENDEN	Jane Fessenden Written Testimony: 12/10/2010
FFOREVER1	Luke Breit, Forests Forever Written Testimony: 12/15/10
FFOREVER2	Luke Breit, Forests Forever Oral Testimony: 12/16/2010
FINE	Joel Fine Written Testimony: 12/14/2010
FIRSTENVIRON1	Tod Delaney, First Environment, Inc. Written Testimony: 12/14/10
FIRSTENVIRON2	Tod Delaney, First Environment, Inc. Oral Testimony: 12/16/2010
FISH	Michael Fish Written Testimony: 12/10/2010
FORD	Austin Ford Oral Testimony: 12/16/2010

FORESTWATCH	Addie Jacobson, Ebbet's Pass Forest Watch Oral Testimony: 12/16/2010
FORMAN	Donald Forman Written Testimony: 11/17/2010
FORMLETTER01	Frank T. Lossy, M.D. and Barbara Steinberg **31 additional commenters submitted similar comments** Written Testimony: 11/27/2010
FORMLETTER02	Doug Pinga **8 additional commenters submitted similar comments** Written Testimony: 12/2/2010
FORMLETTER03	Lew Douglas **9 additional commenters submitted similar comments** Written Testimony: 12/5/2010
FORMLETTER04	John Feins **254 additional commenters submitted similar comments** Written Testimony: 12/7/2010
FORMLETTER05	Melanie Shepherd **111 additional commenters submitted similar comments** Written Testimony: 12/9/2010
FORMLETTER06	Mark Reback **201 additional commenters submitted similar comments** Written Testimony: 12/10/2010
FORMLETTER07	Rachel Medema **6 additional commenters submitted similar comments** Written Testimony: 12/13/2010
FORMLETTER08	Bill Haskins **4175 additional commenters submitted similar comments** Written Testimony: 12/14/2010
FORMLETTER09	Elijah Zarlin, CREDO Action **10578 additional commenters submitted similar comments** Written Testimony: 12/15/2010
FORMLETTER10	Sierra Club California Activists **3309 additional commenters submitted similar comments** Written Testimony: 12/15/2010
FORMLETTER11	Laura Baker et al. Written Testimony: 12/15/10
FRC	Jay Castino, First Record Carbon Written Testimony: 11/4/2010
FREDIANI	Jodi Frediani, Central Coast Forest Watch Oral Testimony: 12/16/2010
FRENCH	Bill French Written Testimony: 12/3/2010
FRERIKS	Shirley Freriks Written Testimony: 12/10/2010
FRESNOMINISTRY	Sarah Sharpe, Fresno Metro Ministry Oral Testimony: 12/16/2010
FRETHEIM	Paul Fretheim Written Testimony: 12/10/2010
FREUND	Ron Freund Written Testimony: 12/13/2010

FREY	Mark Frey Written Testimony: 12/13/2010
FRIEDENBERG	Michael Friedenberg Written Testimony: 12/3/2010
FRIEDMAN	Ruth Friedman Written Testimony: 12/10/2010
FRIENDSOFEARTH	Kate Horner, Friends of the Earth for Asian Indigenous Women's Network; Australian Climate Justice Program; Australian Orangutan Project; Center for International Environmental Law; Civil Society Forum on Climate Justice, Indonesia; ClientEarth; Earth Day Network; FERN; Forum pour la Gouvernance et les Droits de l'Homme (FGDH), Congo; Brazzaville; Friends of the Earth; Greenpeace; Indonesian Center for Environmental Law; International Forum on Globalization; Oxfam; Rainforest Foundation, US; Rainforest Foundation, UK; Rainforest Foundation, Norway; Tebtebba (Indigenous Peoples' International Centre for Policy Research and Education) Written Testimony: 12/12/2010
FRONCE	Linnea Fronce Written Testimony: 12/15/2010
FSCNC	Joanne Drummond, Fire Safe Council of Nevada County Written Testimony: 11/30/2010
FUTRELL	Sherrill Futrell Written Testimony: 12/10/2010
GAGE	Dianne Gage Written Testimony: 12/10/2010
GALLAGHER	Thomas Gallagher Written Testimony: 12/14/2010
GANA	Bill Yanek, Glass Association of North America Written Testimony: 12/15/2010
GARCIA	Felipe Garcia Written Testimony: 11/30/2010
GARDNER	Leanne Gardner Written Testimony: 12/4/2010
GATES	Stillman Gates Written Testimony: 11/30/2010
GDRC	Gary Rynearson, Green Diamond Resource Company Written Testimony: 12/15/2010
GEA	John McCaull, Geothermal Energy Association Written Testimony: 12/7/2010
GERDING	Daniel Gerding Written Testimony: 12/14/2010
GIANNI	PA Gianni Written Testimony: 12/13/2010
GIANNINI	James Giannini Written Testimony: 12/14/2010
GIBBS	David Gibbs Written Testimony: 12/14/2010
GIFFORD	Kevin Gifford Written Testimony: 12/1/2010

GILBERT	Diana Gilbert Written Testimony: 12/14/2010
GILDERSLEEVE1	Todd Gildersleeve Written Testimony: 11/30/2010
GILDERSLEEVE2	Todd Gildersleeve Written Testimony: 12/14/2010
GJEP1	Jeff Conant, Global Justice Ecology Project Written Testimony: 12/15/2010
GJEP2	Jeff Conant, Global Justice Ecology Project Oral Testimony: 12/16/2010
GLICK	Ted Glick Written Testimony: 12/14/2010
GLOVER	Lance Glover Written Testimony: 12/10/2010
GOEDJEN	Robert Goedjen Written Testimony: 12/12/2010
GOFF	Frances Goff Written Testimony: 12/11/2010
GOGLIA	Judi Goglia Written Testimony: 12/2/2010
GPI	Bill Buchan, Graphic Packaging International Written Testimony: 12/8/2010
GRACE	Catherine Grace Written Testimony: 12/13/2010
GRAMMIG	Thomas Grammig Written Testimony: 12/13/2010
GRASSETTI	Richard Grassetti Written Testimony: 12/9/2010
GRAVELLE	Marilynn Gravelle Written Testimony: 12/10/2010
GREENLINING1	C.C. Song, Greenlining Institute Written Testimony: 12/9/2010
GREENLINING2	C.C. Song, Greenlining Institute Oral Testimony: 12/16/2010
GREENPARTY	Michael Feinstein, Green Party Written Testimony: 12/15/2010
GRIGGS	James Griggs Written Testimony: 12/10/2010
GRISHABER	Amy Grishaber Written Testimony: 12/15/2010
GROTHAUS	Greg Grothaus Written Testimony: 12/13/2010
GUERRERO	Roberto Guerrero Written Testimony: 12/9/2010
GWFPS1	Mark Byron, GWF Power Systems Written Testimony: 12/13/2010
GWFPS2	Mark Byron, GWF Power Systems Oral Testimony: 12/16/2010
HAFER	Roth Hafer Written Testimony: 12/9/2010

HAIGHT	Harold and Eva Haight Written Testimony: 12/12/2010
HAMMOND	Anastasia Hammond Written Testimony: 12/14/2010
HANSEN	Diana Hansen Written Testimony: 12/10/2010
HANSON	Larry Hanson Written Testimony: 12/13/2010
HARD	Jim Hard Written Testimony: 12/14/2010
HARPER	Lynn Harper Written Testimony: 12/1/2010
HARRINGTON	Michael Harrington Written Testimony: 12/10/2010
HARRISM	Michael Harris Written Testimony: 12/9/2010
HARRISONE	Eric Harrison Written Testimony: 12/11/2010
HARRISONT	Thomas Harrison Written Testimony: 12/9/2010
HARRISONW	Wesley Harrison Written Testimony: 12/13/2010
HARRISS	Sandra Harris Written Testimony: 11/30/2010
HARRISV	Virginia Harris Written Testimony: 12/10/2010
HASKETT	Adam Haskett Written Testimony: 11/6/2010
HASSEBROCK1	Robert Hassebrock Written Testimony: 12/15/2010
HASSEBROCK2	Robert Hassebrock Oral Testimony: 12/16/2010
HAYDEN	Mary Hayden Written Testimony: 12/9/2010
HDPP1	Bradley K. Heisey, High Desert Power Project Written Testimony: 12/6/2010
HDPP2	Bradley K. Heisey, High Desert Power Project Written Testimony: 12/14/2010
HDPP3	Mike Barr, High Desert Power Project Oral Testimony: 12/16/2010
HECA	Tiffany Rau, Hydrogen Energy California LLC Written Testimony: 12/14/2010
HECKMAN	Dale M. Heckman Written Testimony: 12/9/2010
HENDRICKS	Dottie Hendricks Written Testimony: 12/8/2010
HERNDON	Lew Herndon Written Testimony: 11/30/2010
HERR	Jon Herr Written Testimony: 12/14/2010

HEYN	John Heyn Written Testimony: 12/2/2010
HILLG1	Gary Hill Written Testimony: 11/30/2010
HILLG2	Gary Hill Written Testimony: 12/14/2010
HILLG3	Gary Hill Written Testimony: 12/14/2010
HILLR	Richard Hill Written Testimony: 11/30/2010
HOLMES	Steve Holmes Written Testimony: 11/30/2010
HOOPERASSOC	Pat Hooper, Hooper Associates Written Testimony: 12/10/2010
HOR	Robert Lawrence, Heart of the Oaks Ranch Written Testimony: 12/15/2010
HORNE	Christy Horne Written Testimony: 12/1/2010
HORWITZ	Martin Horwitz Written Testimony: 12/10/2010
HOUSER	Robert Houser Written Testimony: 12/14/2010
HOYT	Edith Hoyt Written Testimony: 12/13/2010
HUDDLESTON	Robert Huddleston Written Testimony: 11/30/2010
HUGHES	Kimberly Hughes Written Testimony: 12/10/2010
HUNTER	Alexandra Hunter Written Testimony: 12/13/2010
HURLEY	Kathleen Hurley Written Testimony: 12/10/2010
HUTCHINGS	Spencer Hutchings Written Testimony: 12/9/2010
ICCT1	Alan Lloyd, International Council on Clean Transport Written Testimony: 12/14/2010
ICCT2	Ed Pike, International Council on Clean Transport Oral Testimony: 12/16/2010
IEPA	Steven Kelly, Independent Energy Producers Association Written Testimony: 12/1/2010
IETA1	Henry Derwent, International Emissions Trading Association Written Testimony: 12/6/2010
IETA2	Ethan Ravage, International Emissions Trading Association Oral Testimony: 12/16/2010
IEUA	Thomas A. Love, Inland Empire Utilities Agency Written Testimony: 12/15/2010
IMPROTA	Richard Improta Written Testimony: 11/30/2010
INDENVASSOC	Patty Krebs, Industrial Environmental Association Oral Testimony: 12/16/2010

IRELAND	Kelly Ireland Written Testimony: 12/14/2010
IWLA1	Stephanie Williams, International Warehouse Logistics Association Written Testimony: 12/15/10
IWLA2	Stephanie Williams, International Warehouse Logistics Association Oral Testimony: 12/16/2010
JACKSON	Bruce Jackson Written Testimony: 12/10/2010
JACOBSONFRIED	David Jacobson-Fried Written Testimony: 12/9/2010
JAMBUSE	Dave Rosenheim, Jambuse Oral Testimony: 12/16/2010
JAMES	Gary James Written Testimony: 12/14/2010
JEMISON	David Jemison Written Testimony: 12/1/2010
JENKINS	Lori Jenkins Written Testimony: 12/1/2010
JEPSON	Donald Jepson Written Testimony: 11/1/2010
JOHNSONA	Angeline Johnson Written Testimony: 12/9/2010
JOHNSONR	Richard Johnson Written Testimony: 12/10/2010
JOHNSONS	Stephen Johnson Written Testimony: 12/10/2010
JONES	Peter Jones Written Testimony: 12/14/2010
JORDAN	Michael Jordan Written Testimony: 12/14/2010
KAISERS	Sharon Kaiser Written Testimony: 12/4/2010
KANGAS	Richard Kangas Written Testimony: 11/30/2010
KAUFMAN	Tayeko Kaufman Written Testimony: 12/10/2010
KEEFER	James Keefer Written Testimony: 12/12/2010
KEITHLEY	Zoe Keithley Written Testimony: 12/10/2010
KELLEY	Mary Kelley Written Testimony: 12/12/2010
KELLOGG	Alan Kellogg Written Testimony: 12/14/2010
KENNEDYA	Arthur Kennedy Written Testimony: 12/11/2010
KENNEDYB	Barbara Kennedy Written Testimony: 12/1/2010

KENNERLY	Justin Kennerly Written Testimony: 12/15/2010
KERNOIL1	Robert Richards, Kern Oil and Refining Company Written Testimony: 12/15/2010
KERNOIL2	Robert Richards, Kern Oil and Refining Company Oral Testimony: 12/16/2010
KINNARE	Bonnie Kinnare Written Testimony: 12/12/2010
KLOSTERMAN	Peter Klosterman Written Testimony: 12/15/2010
KNIGGE	Bernhard Knigge Written Testimony: 12/10/2010
KNOTH	Barb Knoth Written Testimony: 12/10/2010
KOIVISTO	Ellen Koivisto Written Testimony: 12/10/2010
KOPPEL	David Koppel Written Testimony: 12/11/2010
KOWALICK	Martha Kowalick Written Testimony: 12/14/2010
KRAEMER	Susan Kraemer Written Testimony: 12/13/2010
KRAMER	John Kramer Written Testimony: 12/2/2010
KRAY	Gina Kray Written Testimony: 12/10/2010
KRINOCK	Jerome Krinock Written Testimony: 12/10/2010
KUNKEL	Cathy Kunkel Written Testimony: 12/14/2010
KUSTIN01	Camille Kustin, Better World Group; Sara Birmingham, The Solar Alliance; Jay Carlis, Renewable Energy Markets Association Community Energy, Inc.; Jamie Fine, Environmental Defense Fund; Bill Magavern, Sierra Club California; Jennifer Martin, Center for Resource Solutions; Nancy Rader, California Winder Energy Association; Erin Rogers, Union of Concerned Scientists; Danielle Osborn-Mills; The Center for Energy Efficiency and Renewable Technologies; Polly Shaw, Suntech America Written Testimony: 12/7/2010
KUSTIN02	Camille Kustin, Better World Group; Nidia Bautista, Coalition for Clean Air; Bonnie Holmes-Gen, American Lung Association of California; Andy Katz, Breathe California; Bill Magavern, Sierra Club California; Mary Pittman DrPH, Public Health Institute; Shankar Prasad, Coalition for Clean Air; Erin Rogers, Union of Concerned Scientists; Robin Salsburg, Public Health Law Policy Written Testimony: 12/7/2010
KUSTIN03	Camille Kustin, Better World Group; Steve Hamburg Ph.D., Environmental Defense Fund; Roland Hwang, Natural Resources Defense Council; Bill Magavern, Sierra Club California; Jeremy I. Martin Ph.D., Clean Vehicles Program, Union of Concerned

	Scientists; Paul Mason, Pacific Forest Trust; Brian Nowicki, Center for Biological Diversity; John Shears, The Center for Energy Efficiency and Renewable Technologies Written Testimony: 12/7/2010
KUSTIN04	Camille Kustin, Better World Group; Michael Endicott, Sierra Club California; Paul Mason, Pacific Forest Trust; Peter Miller, Natural Resources Defense Council; Brian Nowicki, Center for Biological Diversity; Michelle Passero, The Nature Conservancy Written Testimony: 12/8/2010
KUSTIN05	Camille Kustin, Better World Group; Nick Lapis, Californians Against Waste; Paul Mason, Pacific Forest Trust; Peter Miller, Natural Resources Defense Council; Brian Nowicki, Center for Biological Diversity; Timothy O'Connor, Environmental Defense Fund; Michelle Passero, The Nature Conservancy Written Testimony: 12/9/2010
KUSTIN06	Camille Kustin, Better World Group; Nick Lapis, Californians Against Waste; Elvira Ramirex, Catholic Charities, Diocese of Stockton; Brian Nowicki, Center for Biological Diversity; John Shears, Center for Energy Efficiency and Renewable Technologies; Timothy O'Connor, Environmental Defense Fund; C.C. Song, Greenlining Institute; Peter Miller, Natural Resources Defense Council; Paul Mason, Pacific Forest Trust; Bill Magavern, Sierra Club California; Michelle Passero, The Nature Conservancy Written Testimony: 12/14/2010
KUSTIN07	Camille Kustin, Better World Group; Susan Stephenson, California Interfaith Power and Light; Brian Nowicki, Center for Biological Diversity; James Fine, Environmental Defense Fund; Michelle Chan, Friends of the Earth; Peter Miller, Natural Resources Defense Council; Paul Mason, Pacific Forest Trust; Michael Endicott, Sierra Club California; Michelle Passero, The Nature Conservancy Written Testimony: 12/13/2010
KUSTIN08	Camille Kustin, Better World Group; Elvira Ramirez, Catholic Charities, Diocese of Stockton; Brian Nowicki, Center for Biological Diversity; John Shears, Center for Energy Efficiency and Renewable Technologies; Tyson Eckerle, Energy Independence Now; Steve Hamburg, Environmental Defense Fund; Michelle Chan, Friends of the Earth; C.C. Song, Greenlining Institute; Roland Hwang, Natural Resources Defense Council; Paul Mason, Pacific Forest Trust; Bill Magavern, Sierra Club California; Jeremy I. Martin, Clean Vehicles Program, Union of Concerned Scientists Written Testimony: 12/13/2010
KUSTIN09	Camille Kustin, Better World Group; Ian McGowan, 3Degrees; Sue Kateley, California Solar Energy Industries Association; Nancy Rader, California Wind Energy Association; Nick Lapis, Californians Against Waste; Elvira Ramirez, Catholic Charities, Diocese of Stockton; Danielle Osborn Mills, Center for Energy Efficiency and Renewable Technologies; Jennifer Martin, Center

	for Resource Solutions; Jamie Fine, Environmental Defense Fund; Varner Seaman, Horizon Wind Energy; Kristen Eberhard, Natural Resources Defense Council; Kyle Boudreaux, NextEra Energy; Jay Carlis, Renewable Energy Markets Association, Community Energy, Inc.; Bill Magavern, Sierra Club California; Rachel McMahon, Solar Millennium; Kari Smith, Sunpower; Pollu Shaw, Suntech America; Sara Birmingham, The Solar Alliance; Erin Rogers, Union of Concerned Scientists Written Testimony: 12/13/2010
KUSTIN10	Camille Kustin, Better World Group; Bonnie Holmes-Gen, American Lung Association in California; Any Katz, Breathe California; Elvira Ramirez, Catholic Charities, Diocese of Stockton; Jennifer Martin, Center for Resource Solutions; Barry Vesser, Climate Protection Campaign; James Fine, Environmental Defense Fund; C.C. Song, Greenlining Institute; Kristin Eberhard, Natural Resources Defense Council; Bill Magavern, Sierra Club California; Erin Rogers, Union of Concerned Scientists Written Testimony: 12/13/2010
KUSTIN11	Camille Kustin, Better World Group; Bonnie Holmes-Gen, American Lung Association of California; Andy Katz, Breathe California; Justin Malan, California Conference of Directors of Environmental Health; Susan Stephenson, California Interfaith Power and Light; Ruben Cantu, California Pan-Ethnic Health Network; Elvira Ramirez, Catholic Charities, Diocese of Stockton; John Shears, Center for Energy Efficiency and Renewable Technologies; Nidia Bautista, Coalition for Clean Air; Tyson Eckerle, Energy Independence Now; James Fine, Environmental Defense Fund; C.C. Song, Greenlining Institute; Jeremy Cantor, Healthy Places Coalition; Diane Bailey, Natural Resources Defense Council; Mary Pittman, Public Health Institute; Robin Salsburg, Public Health Law and Policy; Robert Gould, Physicians for Social Responsibility San Francisco-Bay Area Chapter; Manal Aboelata, Prevention Institute; Bill Magavern, Sierra Club California; Shan Magnuson, Sonoma County Asthma Coalition; Erin Rogers, Union of Concerned Scientists; Sonal Patel, White Memorial Pediatric Medical Group Written Testimony: 12/15/2010
KUSTIN12	Camille Kustin, Better World Group; Bonnie Holmes-Gen, American Lung Association in California; Andy Katz, Breathe California; Justin Malan, California Conference of Directors of Environmental Health; Susan Stephenson, California Interfaith Power and Light; Ruben Cantu, California Pan-Ethnic Health Network; William Stringer, California Thoracic Society; Elvira Ramirez, Catholic Charities, Diocese of Stockton; John Shears, Center for Energy Efficiency and Renewable Technologies; Nidia Bautista, Coalition for Clean Air; Shankar Prasad, Coalition for Clean Air; Tyson Eckerle, Energy Independence Now; James Fine, Environmental Defense Fund; C.C. Song, Greenlining Institute; Jeremy Cantor, Healthy Places Coalition; Diane Bailey, Natural Resources Defense Council; Mary Pittman, Public Health

	Institute; Robin Salsburg, Public Health Law and Policy; Robert Gould, Physicians for Social Responsibility San Francisco-Bay Area Chapter Written Testimony: 12/15/10
KUTCHER	Celia Kutcher Written Testimony: 12/9/2010
KYLBERG	Virginia Kylberg Written Testimony: 12/1/2010
LADWP1	Lorraine Paskett, Los Angeles Department of Water and Power Written Testimony: 12/15/2010
LADWP2	Leilani Johnson Kowal, Los Angeles Department of Water and Power Oral Testimony: 12/16/2010
LADWP3	Cindy Parsons, Los Angeles Department of Water and Power Oral Testimony: 12/16/2010
LAFOLLETTE	Paul La Follette Written Testimony: 12/14/2010
LAHISPCHMBR	Andrew Barrera, Los Angeles Metropolitan Hispanic Chamber Oral Testimony: 12/16/2010
LAMALFA	Doug La Malfa, California State Senate Written Testimony: 12/16/2010
LAMPHERE	Steve Lamphere Written Testimony: 12/2/2010
LANDOWSKI	Lona Landowski Written Testimony: 12/9/2010
LANE	Robert Lane Written Testimony: 12/10/2010
LANEW	Maryann LaNew Written Testimony: 12/11/2010
LANGE	Chris Lange Written Testimony: 12/9/2010
LARES	Thora Lares Written Testimony: 12/14/2010
LARIMER	John Larimer Written Testimony: 12/12/2010
LAROSE	Elizabeth Larose Written Testimony: 12/9/2010
LASD1	Frank Caponi, Los Angeles County Sanitation Districts Written Testimony: 12/15/2010
LASD2	Frank Caponi, Los Angeles County Sanitation Districts Oral Testimony: 12/16/2010
LAUMANN	Lynn Laumann Written Testimony: 12/11/2010
LAWRENCEP	Patricia Lawrence Written Testimony: 12/15/2010
LAWRENCER	Robert Lawrence Oral Testimony: 12/16/2010
LENERT	Thomas Lenert Written Testimony: 12/13/2010
LERNER	James Lerner Written Testimony: 12/10/2010

LEVIN	Harvey Levin Written Testimony: 12/10/2010
LEVINSON	Ellis Levinson Written Testimony: 12/10/2010
LEVNO	Stacey Levno Written Testimony: 12/10/2010
LEVY	Hannah Levy Written Testimony: 12/4/2010
LGCRE	John Holladay, Local Government Coalition for Renewable Energy Written Testimony: 12/15/2010 **In addition, 10 supplemental documents were submitted**
LGSEC	Jody London, Local Government Sustainable Energy Coalition Written Testimony: 12/10/2010
LIEBER	Susan Lieber Written Testimony: 12/9/2010
LIFCI	Ruben Jauregui, Latino Institute for Corporate Inclusion Oral Testimony: 12/16/2010
LINNEY	Joan Linney Written Testimony: 12/14/2010
LIPPER	Margaret Lipper Written Testimony: 12/9/2010
LIPPMAN	Norman Lippman Written Testimony: 12/15/2010
LISH	Christopher Lish Written Testimony: 12/14/2010
LITWIN	Laura Litwin Written Testimony: 12/9/2010
LOMAX	Allen Lomax Written Testimony: 12/9/2010
LOMBARD	Edwin Lombard, Edwin Lombard Management Oral Testimony: 12/16/2010
LOTUS	Trisha Lotus Written Testimony: 11/21/2010
LOUIN	Alanna Louin Written Testimony: 12/13/2010
LOZANO	Luis Lozano Written Testimony: 12/10/2010
LUCE	Wiliam Luce Written Testimony: 12/6/2010
LUDLOW	Llewellyn Ludlow Written Testimony: 12/12/2010
LUEKENS	Tom Luekens Written Testimony: 12/2/2010
LUVAAS	Jon Luvaas Written Testimony: 12/9/2010
LYNES	Steve Lynes Written Testimony: 12/14/2010
LYONM	Mary Lyon Written Testimony: 12/13/2010

MACHEN	Ernest Machen Written Testimony: 12/10/2010
MAGILAVY	Beryl Magilavy Written Testimony: 12/14/2010
MANGAI	Jerry Mungai Written Testimony: 12/12/2010
MANGELS	F. Mangels Written Testimony: 12/10/2010
MANNLE	Andy Mannle Written Testimony: 12/11/2010
MARGOLIS	Josh Margolis Oral Testimony: 12/16/2010
MARKS	Charles Marks Written Testimony: 12/14/2010
MARS	Raymond Mars Written Testimony: 11/30/2010
MARTINN	Nicholas Martin; John Kadyszewski, American Carbon Registry; Frank Tugwell, Winrock International Written Testimony: 12/13/2010 **In addition, 3 supplemental documents were submitted**
MARTINR	Rudolf Martin Written Testimony: 12/10/2010
MASCARENHAS	Michelle Mascarenhas Written Testimony: 12/15/2010
MASSMANJ	Luke Massman-Johnson Written Testimony: 12/10/2010
MATHEWS	John Mathews Written Testimony: 12/10/2010
MATTOX	Karen Mattox Written Testimony: 11/30/2010
MATZEK	Virginia Matzek Written Testimony: 12/14/2010
MAYER	Donald Mayer Written Testimony: 12/9/2010
MAYNE	Judy Mayne Written Testimony: 12/12/2010
MAYWALD	Persephone Maywald Written Testimony: 12/10/2010
MAZOWITA	Michael Mazowita and Beth Vaughan, California Cogeneration Council Written Testimony: 12/15/2010
MCADAMS	Bonnie McAdams Written Testimony: 11/30/2010
MCCARTER	C.J. McCarter Written Testimony: 12/12/2010
MCCARTHYJ	Jennifer McCarthy Written Testimony: 12/1/2010
MCCARTHYV	Veronica McCarthy Written Testimony: 12/6/2010

MCGLASSON	David McGlasson Written Testimony: 11/30/2010
MCIW	John Spangler, Marine Corps Installations West Oral Testimony: 12/16/2010
MCKINSTRY	Sara Fastenberg, McKinstry Company Written Testimony: 12/21/2010
MCLAUGHLIN	William McLaughlin Written Testimony: 12/10/2010
MELL	Sheila Mell Written Testimony: 11/30/2010
MGD	Mike O'Kelly, Morning Glory Dairy Written Testimony: 11/30/2010
MGMI	Daniel Smyth, MGM Innova Written Testimony: 12/14/2010
MICHETTI	Susan Michetti Written Testimony: 12/9/2010
MID1	Elizabeth Hadley, Modesto Irrigation District; Joy Warren, Modesto Irrigation District; Dan Severson, Turlock Irrigation District Written Testimony: 12/10/2010
MID2	Joy Warren, Modesto Irrigation District Oral Testimony: 12/16/2010
MILLERF	Felicia Miller Written Testimony: 12/11/2010
MILLERJEF	Jeff Miller Written Testimony: 12/8/2010
MILLERJEN	Jennifer Miller Written Testimony: 12/13/2010
MILLERKEN1	Ken Miller Written Testimony: 12/10/2010
MILLERKEN2	Ken Miller Written Testimony: 11/22/2010
MILLERKENDR	Kendrick Miller Written Testimony: 12/9/2010
MILLERWILL	William Joseph Miller Written Testimony: 12/11/2010
MILLS	Melva Mills Written Testimony: 12/12/2010
MINAULT	Kent Minault Written Testimony: 12/11/2010
MINES	Holly Mines Written Testimony: 12/15/2010
MOCIUN	Marilyn Mociun Written Testimony: 12/14/2010
MONTANA	Peter Montana Written Testimony: 12/14/2010
MONTE	Dan Monte Written Testimony: 12/14/2010
MOORE	Alan Moore Written Testimony: 12/10/2010

MOORHEAD	Bruce Moorhead Oral Testimony: 12/16/2010
MORRISG	Gregg Morris Oral Testimony: 12/16/2010
MORRISM	Mr. and Mrs. Mike Morris Written Testimony: 12/1/2010
MORRISS	Sharon Morris Written Testimony: 12/9/2010
MORSE	Susan Morse Written Testimony: 12/10/2010
MORTIMER	Hal Mortimer Written Testimony: 11/30/2010
MOYNAHAN	Susan Moynahan Written Testimony: 12/11/2010
MRC	Alison Freedlund, Mattole Restoration Council Written Testimony: 11/22/2010
MSCG2	Steve Huhman, Morgan Stanley Capital Group, Inc. Written Testimony: 12/13/2010
MUELLERD	Darryl Mueller Written Testimony: 12/2/2010
MUELLERS	Sharon Mueller Written Testimony: 11/30/2010
MURDOCH	Phyllis Murdoch Written Testimony: 12/10/2010
MURGUIA	Sharon Murguia Written Testimony: 12/1/2010
MURPHYE	Edward Murphy Written Testimony: 12/16/10
MURPHYH	Henry Murphy Written Testimony: 12/13/2010
MURRAY	Mike Murray Written Testimony: 12/1/2010
MWDSC1	Jeff Kightlinger, Metropolitan Water District of Southern California Written Testimony: 12/14/2010
MWDSC2	Mark Parsons, Metropolitan Water District of Southern California Oral Testimony: 12/16/2010
MYERSG1	Greg Myers Written Testimony: 11/30/2010
MYERSG2	Gary Myers Written Testimony: 12/7/2010
MYERSH	Howard Myers Written Testimony: 12/12/2010
MYERSR	Rachel Myers Written Testimony: 12/13/2010
NAIMA	Angus E. Crane, North American Insulation Manufacturers Association Written Testimony: 12/15/2010
NARITELLI	Lawrence Naritelli Written Testimony: 12/7/2010

NAUSBAUM	Nora Nausbaum Written Testimony: 12/9/2010
NC1	Michelle Passero, The Nature Conservancy Written Testimony: 11/23/2010
NC2	Michelle Passero, The Nature Conservancy Written Testimony: 12/7/2010
NC3	Michelle Passero, The Nature Conservancy; Paul Mason, Pacific Forest Trust; Stephanie Reyes, Greenbelt Alliance; Stuart Cohen, Transform; James Fine, Environmental Defense Fund; Rachel Dinno Taylor, Trust for Public Land; Bettina Ring, Bay Area Open Space Council; William Schroeer, Smart Growth America; Dan Taylor, Audubon California; Dan Silver, Endangered Habitats League; Bill Keene, Sonoma County Agricultural Preservation and Open Space District; Judy Corbett, Local Government Commission Written Testimony: 12/8/2010
NC4	Lizette Weiss, The Nature Conservancy Written Testimony: 12/11/2010
NC5	Julia Gardiner, The Nature Conservancy; Michelle Passero, The Nature Conservancy; Paul Mason, Pacific Forest Trust; Stephanie Reyes, Greenbelt Alliance; Stuart Cohen, Transform; Elyse Low, Move San Diego; Jenne Merrill, California Climate & Agriculture Network; Jame Fine, Environmental Defense Fund; Rachel Dinno Taylor, Trust for Public Land; Bettina Ring, Bay Area Open Space Council; William Schroeer, Smart Growth America; William Leahy, Big Sur Land Trust; Bill Keene, Sonoma County Agricultural Preservation and Open Space District; Dan Taylor, Audubon California; Dan Silver, Endangered Habitats League; Kim Delfino, Defenders of Wildlife; Judy Corbett, Local Government Commission; Ann Chan, Center for Clean Air Policy; Tyson Eckerle, Energy Independence Now Written Testimony: 12/14/2010
NC6	Michelle Passero, The Nature Conservancy Oral Testimony: 12/16/2010
NC7	Louis Blumberg, The Nature Conservancy Oral Testimony: 12/16/2010
NCPA1	Susie Berlin, Northern California Power Agency Written Testimony: 12/15/2010
NCPA2	Susie Berlin, Northern California Power Agency Oral Testimony: 12/16/2010
NCTPP1	Lance McCray, NOR CAL TPP Written Testimony: 12/1/2010
NCTPP2	Lance McCray, NOR CAL TPP Written Testimony: 12/8/2010
NDRC	Glenn Wolf, National Development and Reform Commission Written Testimony: 12/10/2010
NEAL	Yvonne Neal Written Testimony: 12/11/2010
NELSON	Pam Nelson Written Testimony: 11/18/2010

NESCO	Daren Anderson, NESCO Written Testimony: 11/4/2010
NEWELL	Brent Newell, Center on Race, Poverty and the Environment Oral Testimony: 12/16/2010
NEWFOREST	Brian Shillinglaw, New Forests; Toby Janson-Smith, Conservation International; Derek Walker, Environmental Defense Fund; Joy Warren, Modesto Irrigation District; Louis Blumberg, The Nature Conservancy; Robert Parkhurst, Pacific Gas & Electric Company; Elizabeth Hadley, City of Redding; Mike Bloom, City of Roseville; Tim Tutt, Sacramento Municipal Utility District; Leslie Durschinger, Terra Global Capital; Dan Severson, Turlock Irrigation District Written Testimony: 12/15/2010
NEWMAN	Nancy Newman Written Testimony: 12/12/2010
NEXANT	Paul MacGregor, Nexant Written Testimony: 12/13/2010
NEXTERAENERGY	Kyle Boudreaux, NextEra Energy Resources Written Testimony: 12/14/2010
NGUYEN	Binh Nguyen Written Testimony: 12/10/2010
NIELSEN	Charlene Nielsen Written Testimony: 12/14/2010
NISSENBAUM	Scott Nissenbaum, Finite Carbon Corporation Written Testimony: 11/29/2010
NORDYKE	Tim Nordyke Written Testimony: 12/1/2010
NORRIS	Nicole Norris Written Testimony: 11/30/2010
NRDC1	Kristin Eberhard, Natural Resources Defense Council Written Testimony: 12/6/2010
NRDC2	Kristen Eberhard, Natural Resources Defense Council Oral Testimony: 12/16/2010
NRDC3	Alex Jackson, Natural Resources Defense Council Oral Testimony: 12/16/2010
NRDC4	Alex Jackson, Natural Resources Defense Council Written Testimony: 12/16/10
NRGENERGY	Brannen McElmurray, NRG Energy Written Testimony: 12/14/2010
OFFEN	Bernard Offen Written Testimony: 12/10/2010
OFFSETSWG1	Bruce McLaughlin, Offsets Working Group for Joy Warren, Modesto Irrigation District; Elizabeth Hadley, City of Redding; Michael Bloom, City of Roseville; Timothy Tutt, Sacramento Municipal Utility District; Dan Severson, Turlock Irrigation District Written Testimony: 12/15/2010
OFFSETSWG2	Bruce McLaughlin, Offsets Working Group Oral Testimony: 12/16/2010
OLAMWC	Marian Balster, Olam West Coast Oral Testimony: 12/16/2010

OLIVEIRA1	Ciyin Oliveira Oral Testimony: 12/16/2010
OLIVEIRA2	Ciyin Oliveira Written Testimony: 12/16/10
OLIVEIRAM	Mauro Oliveira, Stop Clearcutting California Oral Testimony: 12/16/2010
OLSON	Dean Olson Written Testimony: 12/13/2010
OOGC	Barbara Zimmermann, Occidental Oil and Gas Corporation; Frank Komin, Oxy Long Beach Inc. Written Testimony: 11/15/2010
OPC	Carl Wirdak, Occidental Petroleum Corporation Written Testimony: 12/15/2010
ORMAT	Paul Thomsen, Ormat Technologies, Inc. Written Testimony: 12/14/2010
OSTWALD	David Ostwald Written Testimony: 12/10/2010
OWENSIL	Mark Tussing, Owens-Illinois Written Testimony: 12/15/2010
PACIFICOR1	Eric Chung, PacifiCorp Written Testimony: 12/15/2010
PACIFICOR2	Eric Chung, PacifiCorp Oral Testimony: 12/16/2010
PACKER	Keith Packer Written Testimony: 11/30/2010
PAHRE	Barbara Pahre Written Testimony: 12/9/2010
PALM	Aaron Palm Written Testimony: 11/30/2010
PALOCSAY	Sondra Palocsay Written Testimony: 11/30/2010
PAPPANO	Pablo Pappano Written Testimony: 12/3/2010
PARIGORIS	Kim Parigoris Written Testimony: 12/14/2010
PARKER	Vivian Parker Written Testimony: 12/15/2010
PARLETTE	Karen Parlette Written Testimony: 12/13/2010
PATTON	Dennis Patton Written Testimony: 12/11/2010
PAYNE	Julie Payne Written Testimony: 12/10/2010
PCAPCD	Thomas Christofk, Placer County Air Pollution Control District Written Testimony: 12/10/2010
PEABODY	Steve Peabody Written Testimony: 11/7/2010
PEABODYENERGY	Peter Glaser, Peabody Energy Company Written Testimony: 12/15/2010

PENCE	Janet Pence Written Testimony: 12/7/2010
PERATA	Antonia Perata Written Testimony: 12/11/2010
PERMANENCE	Ed Murphy, Permanence Committee Oral Testimony: 12/16/2010
PERRIN	Gael Perrin Written Testimony: 12/13/2010
PETLOCK	Kyle Petlock Written Testimony: 12/10/2010
PETRALIA	Jim Petralia Written Testimony: 12/10/2010
PFEIFFER	Jennifer Pfeiffer Written Testimony: 12/11/2010
PFT1	Paul Mason, Pacific Forest Trust Written Testimony: 12/8/2010
PFT2	Paul Mason, Pacific Forest Trust Oral Testimony: 12/16/2010
PGE1	John Busterud, Pacific Gas and Electric Company Written Testimony: 12/2/2010
PGE2	Kate Beardsley, Pacific Gas and Electric Company Oral Testimony: 12/16/2010
PGE3	Robert Parkhurst, Pacific Gas and Electric Company Oral Testimony: 12/16/2010
PHELPS	Virginia Phelps Written Testimony: 12/2/2010
PHILLIPSE	Erin Phillips Written Testimony: 12/13/2010
PHILLIPSS	Stu Phillips Written Testimony: 12/9/2010
PHTA	Jack Weir, Pleasant Hill Taxpayers Association Written Testimony: 12/2/2010
PIC	Marilyn Jasper, Public Interest Coalition Written Testimony: 12/6/2010
PINKSTON1	Pam Pinkston Written Testimony: 12/14/2010
PINKSTON2	Pam Pinkston Oral Testimony: 12/16/2010
PLANK	Laurie Plank Written Testimony: 12/9/2010
PLOTKIN	Norman Plotkin, Plotkin Zins Written Testimony: 12/15/10
PMTPETRO1	Steven Farkas, Paramount Petroleum Written Testimony: 12/15/2010
PMTPETRO2	Gary Grimes, Paramount Petroleum Oral Testimony: 12/16/2010
PMTPETRO3	Gary Grimes, Paramount Petroleum Written Testimony: 12/16/10
POLANSKY	Debra Polansky Written Testimony: 12/10/2010

POLLOCK	Wendy Lou Pollock Written Testimony: 12/10/2010
PORTERJ	Joey Porter Written Testimony: 12/12/2010
PORTERK	Keith Porter Written Testimony: 12/13/2010
POTTER	Phillip Potter Written Testimony: 12/11/2010
POUSMAN	D.O. Pousman Written Testimony: 12/11/2010
POWELL	Dan Powell Written Testimony: 12/1/2010
POWERSD	David Powers Written Testimony: 12/10/2010
POWERSW	Wendy Powers Written Testimony: 12/10/2010
PRAXAIR	John Calka, Praxair Inc. Written Testimony: 12/15/2010
PRESSBURGER	Thomas Pressburger Written Testimony: 12/11/2010
PRICEK	Kenneth Price Written Testimony: 12/9/2010
PRICES	Dr. Sharon and James Price Written Testimony: 12/9/2010
PUBLICUTILITIES	Frank Harris, Public Utilities Written Testimony: 12/16/10
RAADIK	Lynn Raadik Written Testimony: 12/2/2010
RADCLIFFE	Steve Radcliffe Written Testimony: 12/9/2010
RAMIREZA	Armando Ramirez Oral Testimony: 12/16/2010
RAMIREZJ	Juan Ramirez Oral Testimony: 12/16/2010
RAMSEY	David Ramsey Written Testimony: 11/30/2010
RANDALL	Christy Randall Written Testimony: 11/30/2010
RAPHAEL	Joan Raphael Written Testimony: 12/10/2010
RAPINI	Anthony Rapini Written Testimony: 11/30/2010
RATLIFF	Marillyn Ratliff Written Testimony: 11/30/2010
RATZLAFF	Karen Ratzlaff Written Testimony: 12/9/2010
RAY	Peggy Ray Written Testimony: 11/30/2010
RCRC	Staci Heaton, Regional Council of Rural Counties Written Testimony: 12/9/2010

REAVES	John Reaves Written Testimony: 12/15/2010
REC	Robert (Bob) Stockton, Rick Engineering Company Written Testimony: 12/16/10
REED	Natalie Reed Written Testimony: 12/13/2010
REGINATO	Jim Reginato Written Testimony: 12/11/2010
REHG	Charmaine M. Rehg Written Testimony: 12/14/2010
REILLY	Mark Reilly Written Testimony: 12/11/2010
REISIG	William Reisig Written Testimony: 12/1/2010
RELECTRIC	Elizabeth Hadley, Redding Electric Utility Oral Testimony: 12/16/2010
REMA	Joseph Seymour, Renewable Energy Markets Association Written Testimony: 12/15/2010
RENTON	Barbara Renton Written Testimony: 12/11/2010
RFA	Bob Dinneen, Renewable Fuels Association Written Testimony: 12/13/2010
RICHARDS	Jennie Richards Written Testimony: 12/13/2010
RICHARDSON	Michael Richardson Written Testimony: 12/11/2010
RICKER	Michelle Ricker Written Testimony: 12/3/2010
RIEBEL	Linda Riebel Written Testimony: 12/9/2010
RIEVE	Theresa Rieve Written Testimony: 12/12/2010
RITCHIEC	Cheryl Ritchie Written Testimony: 12/11/2010
RITCHIES	Shann and Dennis Ritchie Written Testimony: 12/10/2010
RIVENES	Don Rivenes Written Testimony: 12/14/2010
ROBBINS	Anthony Robbins Written Testimony: 12/10/2010
ROBERTSJ	Jeff Roberts Written Testimony: 12/10/2010
ROBERTSK	Ken Roberts Written Testimony: 11/30/2010
ROBERTSONR	Ruth Robertson Written Testimony: 12/14/2010
ROCA	Nancy Roca Written Testimony: 12/11/2010
RODOWICZ	Maxine Rodowicz Written Testimony: 12/15/2010

ROLLEY	Wesley Rolley Written Testimony: 12/10/2010
ROLLS	Denise and Jeff Rolls Written Testimony: 11/30/2010
ROMAIN	David Romain Written Testimony: 12/14/2010
ROTH	Constance Roth Written Testimony: 12/15/2010
SACHISPCHMBR	Steve Gandola, Sacramento Hispanic Chamber of Commerce Oral Testimony: 12/16/2010
SACREB	Karen Klinger Written Testimony: 12/16/10
SALERNO	Marie Salerno Written Testimony: 12/12/2010
SAMARDICH	Barbara Samardich Written Testimony: 11/30/2010
SANDBAGCC	Bryony Worthington, Sandbag Climate Campaign Written Testimony: 12/14/2010
SANDERS	Brandon Sanders Written Testimony: 12/14/2010
SANSONE	Nicholas J. Sansone Written Testimony: 12/12/2010
SARRIS	Dorian Sarris Written Testimony: 12/10/2010
SAUNDERS	Brad Saunders Written Testimony: 12/10/2010
SAYBLE	Susan Sayble Written Testimony: 12/9/2010
SBCA1	Scott Hauge, Small Business California Oral Testimony: 12/16/2010
SBCA2	Hank Ryan, Small Business California Written Testimony: 12/14/2010
SBMAJ1	John Arensmeyer, Small Business Majority Written Testimony: 12/16/2010
SBMAJ2	John Arensmeyer, Small Business Majority Oral Testimony: 12/16/2010
SCAQMD1	Barry Wallerstein, South Coast Air Quality Management District Written Testimony: 12/14/2010
SCAQMD2	Jill Whynot, South Coast Air Quality Management District Written Testimony: 12/14/10
SCAQMD3	Jill Whynot, South Coast Air Quality Management District Oral Testimony: 12/16/2010
SCB	John Fitzgerald, Society for Conservation Biology Written Testimony: 12/6/2010
SCCBOS	Tony Campos, Santa Cruz County Board of Supervisors Written Testimony: 12/14/2010
SCE1	Nancy Allred, Southern California Edison Written Testimony: 12/10/2010
SCE2	Frank Harris, Southern California Edison Oral Testimony: 12/16/2010

SCHAEFER	Biff Schaefer Written Testimony: 12/14/2010
SCHANER	Ron Schaner Written Testimony: 11/30/2010
SCHEIBE	Leah Scheibe Written Testimony: 12/13/2010
SCHERMERHORN	Sherry Schermerhorn Written Testimony: 12/14/2010
SCHLICHTER	June Schlichter Written Testimony: 12/15/2010
SCHRANK	Sirley Schrank Written Testimony: 12/2/2010
SCHUETZ	Nicole Schuetz Written Testimony: 12/10/2010
SCHULTE	Barbara Schulte Written Testimony: 11/30/2010
SCOTT	Susanne Scott Written Testimony: 12/9/2010
SCPPA1	Norman Pedersen, Southern California Public Power Authority Written Testimony: 12/1/2010
SCPPA2	Norman Pedersen, Southern California Public Power Authority Written Testimony: 12/6/2010
SCPPA3	Norman A. Pederson, Southern California Public Power Authority Written Testimony: 12/15/2010
SCPPA4	Bill Carnahan, Southern California Public Power Authority Oral Testimony: 12/16/2010
SCPPA5	Norman Pedersen, Southern California Public Power Authority Oral Testimony: 12/16/2010
SCS	Robert Hrubes, Scientific Certification Systems Written Testimony: 12/15/2010
SCWA	Chris Mertens, Sonoma County Water Agency Written Testimony: 12/16/10
SDCHAMBER	Angelika Villagrana, San Diego Regional Chamber of Commerce Written Testimony: 12/15/2010
SDSU	Laura Emery, San Diego State University Written Testimony: 12/11/2010
SEAL	Kathy Seal Written Testimony: 11/18/2010
SEAMAN	Gerda Seaman Written Testimony: 12/11/2010
SEECH	Randal Seech Written Testimony: 12/9/2010
SELLERS	Amy Sellers Written Testimony: 12/8/2010
SEMPRA1	Tamara Rasberry, Sempra Energy Utility Written Testimony: 12/14/2010
SEMPRA2	Tamara Rasberry, Sempra Energy Utility; Southern California Gas Company; San Diego Gas and Electric Oral Testimony: 12/16/2010

SENKEHOE	Christine Kehoe, California State Senate Written Testimony: 12/14/2010
SFMAYOR1	Calla Ostrander, City and County of San Francisco Written Testimony: 12/15/10
SFMAYOR2	Calla Ostrander, City and County of San Francisco Oral Testimony: 12/16/2010
SFPUC1	James Hendry and Bart Broome, San Francisco Public Utilities Commission Written Testimony: 12/9/2010
SFPUC2	James Hendry, San Francisco Public Utilities Commission Oral Testimony: 12/16/2010
SFPUC3	James Hendry, San Francisco Public Utilities Commission Written Testimony: 12/16/10
SHELLENERGY	Marcie Milner, Shell Energy North America Written Testimony: 12/14/2010
SHELLITO	Jeff Shellito Oral Testimony: 12/16/2010
SHILLINGLAW1	Brian Shillinglaw, New Forests Written Testimony: 12/15/2010
SHILLINGLAW2	Brian Shillinglaw Oral Testimony: 12/16/2010
SIEBERN	Diane Siebern Written Testimony: 12/1/2010
SIERRACLUB1	Sue Lynn, Sierra Club Written Testimony: 12/14/2010
SIERRACLUB2	Karen Miki, Sierra Club Oral Testimony: 12/16/2010
SIERRACLUB3	Marily Woodhouse, Sierra Club Oral Testimony: 12/16/2010
SIERRACLUB4	Marily Woodhouse, Sierra Club Written Testimony: 12/20/10
SIERRACLUBCA1	Edward Mainland, Sierra Club California Written Testimony: 11/17/2010
SIERRACLUBCA2	Michael Endicott, Sierra Club California Oral Testimony: 12/16/2010
SIERRACLUBCA3	Bill Magavern, Sierra Club California Oral Testimony: 12/16/2010
SIERRACLUBCA4	Bill Magavern, Sierra Club California Written Testimony: 12/15/10
SIMON	Philip Simon Written Testimony: 12/13/2010
SIMS	Katherine Sims Written Testimony: 12/15/2010
SIRCAR	Subrata Sircar Written Testimony: 12/12/2010
SJCHISPCHMBR	Tim Martinez, San Joaquin County Hispanic Chamber of Commerce Oral Testimony: 12/16/2010
SMEDLY	John Smedley Written Testimony: 12/8/2010

SMITHG	Gaye Smith Written Testimony: 12/9/2010
SMITHM	Melinda Smith Written Testimony: 12/1/2010
SMITHR	Ralph Smith Written Testimony: 12/3/2010
SMITHS	Steven Smith, Verallia Written Testimony: 12/15/2010
SMUD1	William Westerfield, Sacramento Municipal Utility District Written Testimony: 12/15/2010
SMUD2	Timothy Tutt, Sacramento Municipal Utility District Oral Testimony: 12/16/2010
SMULEVITZ	Karen Smulevitz Written Testimony: 12/14/2010
SNOWDENB	Bill Snowden Written Testimony: 11/30/2010
SNOWDENT	Tammy Snowden Written Testimony: 11/30/2010
SOBO	Naomi Sobo Written Testimony: 12/12/2010
SODERLING	John Soderling Written Testimony: 12/2/2010
SOL1	Mahaia Sol Oral Testimony: 12/16/2010
SOL2	Mahaia Sol Written Testimony: 12/16/10
SOLARTURBINES1	Craig Anderson, Solar Turbines Written Testimony: 12/14/2010
SOLARTURBINES2	Craig Anderson, Solar Turbines Oral Testimony: 12/16/2010
SOLOMON	Richard and Chihoko Solomon Written Testimony: 12/10/2010
SONOMAFCC	John Donnelly, Sonoma's First Congregational Church Written Testimony: 12/12/2010
SOONG	Daniel Soong Written Testimony: 12/9/2010
SPAISER	Leslie Spaiser Written Testimony: 12/10/2010
SPI	Mark Pawlicki, Sierra Pacific Industries Oral Testimony: 12/16/2010
SREDANOVIC	Gail Sredanovic Written Testimony: 12/9/2010
ST	S. T. Written Testimony: 12/7/2010
STARNES	Joseph Starnes Written Testimony: 11/30/2010
STARRY	Mike Starry Written Testimony: 12/11/2010
STEELEB	Brad Steele Written Testimony: 12/10/2010

STEELER	Renae Steele Written Testimony: 12/14/2010
STEINBORN	Cathrine Steinborn Written Testimony: 12/12/2010
STEINMAN	James R. Steinman Written Testimony: 12/9/2010
STEINMANA	Andee Steinman Written Testimony: 12/9/2010
STEPHENS	John and Sarah Stephens Written Testimony: 11/17/2010
STEVENSON	Richard Stevenson Written Testimony: 11/30/2010
STEWARTJ	Jim Stewart Written Testimony: 12/15/2010
STEWARTM1	Melinda Stewart Written Testimony: 12/10/2010
STEWARTM2	Melinda Stewart Written Testimony: 12/10/2010
STOLTZFUS	Alan Stoltzfus Written Testimony: 12/10/2010
STONE	Leonard Stone Written Testimony: 12/1/2010
STONEMAN	Jamie Stoneman Written Testimony: 12/4/2010
SUAREZ	Juan Suarez Written Testimony: 12/11/2010
SUCKOW	Paul Suckow Written Testimony: 12/14/2010
SULLIVAN	Joseph Sullivan Written Testimony: 12/1/2010
SUMMER	Sandy Summer Written Testimony: 12/9/2010
SUNONESOLUT	Konrad Huber, SunOne Solutions; Octavio de Guimarães Horta, VO2 Desenvolvimento Empresarial; Fernando A.F. de Souza, GreenCO2; Aurélio de Andrade Souza, Usinazul- Sustainable Energy and Environmental Services, Ecomapuá; Stefano and Brennan Merlin/Duty, Instituto Ecológica Sustainable Carbon Written Testimony: 12/13/2010
SUSHABITAT	Robert Means, Sustainable Habitat Written Testimony: 12/10/2010
SUSTAINDESIGN	Priscilla Rich, Sustainable Design Written Testimony: 12/10/2010
SVM	Ross May, Searles Valley Minerals Written Testimony: 12/2/2010
SWC1	Terry Erlewine, State Water Contractors Written Testimony: 12/14/2010
SWC2	Craig Jones, State Water Contractors Oral Testimony: 12/16/2010
SWGASCORP	Catherine Mazzeo, Southwest Gas Corporation Written Testimony: 12/15/2010

TASSARO	Steve Tassaro Oral Testimony: 12/16/2010
TAUSSIG	Tom Taussig Written Testimony: 12/9/2010
TAYLORC	Courtenay Taylor Written Testimony: 12/11/2010
TAYLORE	Elizabeth Taylor Written Testimony: 12/13/2010
TAYLORS	Sandra Taylor Written Testimony: 12/6/2010
TCF	Chris Kelly, The Conservation Fund Written Testimony: 12/11/2010
TELACU	David Lizarraga, TELACU Millennium Oral Testimony: 12/16/2010
TERSOL	Antony Tersol Written Testimony: 12/11/2010
TESORO	Daniel Riley, Tesoro Companies, Inc. Written Testimony: 12/14/2010
TFI	William Herz, The Fertilizer Institute Written Testimony: 12/15/2010
THIBODEAUX	John Thibodeaux Written Testimony: 11/30/2010
THOMAS	Joanne Thomas Written Testimony: 12/12/2010
THOMSON	Anita Thomson Written Testimony: 12/12/2010
TITUS	Bill Titus Written Testimony: 12/14/2010
TOUCHSTONE	Gina Touchstone Written Testimony: 12/9/2010
TOZZINI	Leslie Tozzini Written Testimony: 12/14/2010
TPI1	Erin Craig, TerraPass Inc. Written Testimony: 12/9/2010
TPI2	Erin Craig, TerraPass Inc. Written Testimony: 12/15/2010
TPI3	Erin Craig, TerraPass Inc. Written Testimony: 12/15/2010
TPI4	Erin Craig, TerraPass Inc. Oral Testimony: 12/16/2010
TREEFOUNDTN	Jan Summers, Tree Foundation Written Testimony: 12/14/2010
TRI	Jack Nilles, Telecommuting Research Institute Written Testimony: 12/10/2010
TURNER	Jay Turner Written Testimony: 12/10/2010
UC1	Anthony Garvin, University of California Written Testimony: 12/3/2010
UC2	Anthony Garvin, University of California Oral Testimony: 12/16/2010

UCB	William Stewart, University of California Berkeley Written Testimony: 12/10/2010
UCS1	Erin Rogers, Union of Concerned Scientists Written Testimony: 11/23/2010
UCS2	Dan Kalb, Union of Concerned Scientists Written Testimony: 12/10/2010
UCS3	Jasmin Ansar, Union of Concerned Scientists et al. Written Testimony: 12/15/2010
UCS4	Jasmin Ansar, Union of Concerned Scientists; Global Warming Action Coalition Oral Testimony: 12/16/2010
UCS5	Erin Rogers, Union of Concerned Scientists Oral Testimony: 12/16/2010
UNGER	Art Unger Written Testimony: 11/17/2010
UNITEDAIRLINES	Robert Madigan, United Airlines Written Testimony: 12/15/2010
USD	Hugh Ellis, University of San Diego Written Testimony: 12/10/2010
USDOD1	C.L. Stathos, United States Department of Defense Written Testimony: 12/14/2010
USDOD2	Randal Friedman, United States Department of Defense Oral Testimony: 12/16/2010
USFLAW	Alice Kaswan, University of San Francisco School of Law Written Testimony: 12/10/2010
USFWS	Gabriela Chevarria, United States Fish and Wildlife Service Written Testimony: 12/14/2010
USGSRETIRED	Steve Eittreim Written Testimony: 12/10/2010
VALDEZ	Bruno Simon Valdez Written Testimony: 12/12/2010
VALERO	Matthew H. Hodges, Valero Companies Written Testimony: 12/15/2010
VANATTA	Debra Vanatta Written Testimony: 11/30/2010
VANOOSTERHOUT	Bob Van Oosterhout Written Testimony: 12/12/2010
VARON	Gil Varon Written Testimony: 12/10/2010
VCS	David Antonioli, Voluntary Carbon Standard Written Testimony: 12/15/2010
VESSER	Barry Vesser Written Testimony: 12/10/2010
VIRGA	Carla Virga Written Testimony: 11/30/2010
VWCSLV	Nancy Macy, Valley Women's Club of San Lorenzo Valley Written Testimony: 11/18/2010
WAKEHAM	Chris Wakeham Written Testimony: 12/14/2010

WALLACE	Anne Wallace Written Testimony: 12/14/2010
WALTERS	Myron Walters Written Testimony: 12/10/2010
WANG	T.K. Wang Written Testimony: 12/10/2010
WAPA	Koji Kawamura, Western Area Power Administration Written Testimony: 12/15/2010
WARNER	Charles Warner Written Testimony: 12/10/2010
WEC	Doug Davie, Wellhead Electric Company Written Testimony: 12/14/2010
WEINSTEIN	Jeremy Weinstein, Law Offices of Jeremy D. Weinstein Written Testimony: 12/1/2010
WEISS	Ken Weiss Written Testimony: 12/10/2010
WELLSTED	Ted Wells, Written Testimony: 12/14/2010
WELLSWILL	William Wells Written Testimony: 12/14/2010
WENZEL	Ruth Wenzel Written Testimony: 12/10/2010
WESSELS	John Wessels Written Testimony: 11/30/2010
WESTERND	Dan Western Written Testimony: 12/2/2010
WESTERNS	Shane Western Written Testimony: 12/12/2010
WHEELER	Justine Wheeler Written Testimony: 11/30/2010
WHIPPLE	Stann Whipple Written Testimony: 12/13/2010
WHITEK	Kaiba White Written Testimony: 12/14/2010
WHITER	Richard White Written Testimony: 12/10/2010
WIECK	James Wieck Written Testimony: 11/30/2010
WILCOX	Christina Wilcox Written Testimony: 12/10/2010
WILLARD	Alan Willard Written Testimony: 12/1/2010
WILLIAMSA	Angie Williams Written Testimony: 12/10/2010
WILLIAMSZ	Laurie Williams and Allan Zabel Written Testimony: 12/13/2010
WIRA1	Craig Moyer, Western Independent Refiners Association Written Testimony: 12/15/2010
WIRA2	Craig Moyer, Western Independent Refiners Association Oral Testimony: 12/16/2010

WITT	Ortrud Witt Written Testimony: 12/4/2010
WITTWER	Jonathan Wittwer Written Testimony: 12/12/2010
WM1	Charles White, Waste Management Written Testimony: 12/15/2010
WM2	Charles White, Waste Management Oral Testimony: 12/16/2010
WOLF	Peter Wolf Written Testimony: 12/9/2010
WOLPERT	Bill Wolpert Written Testimony: 12/10/2010
WOLPOW	Sarah Wolpow Written Testimony: 12/9/2010
WOODWARD	M. Woodward Written Testimony: 12/6/2010
WPA	Kent W. Noyes, Water and Power Associates Written Testimony: 12/6/2010
WPTF	Clare Breidenich, Western Power Trading Forum Written Testimony: 12/3/2010
WREN	Barranca Wren, Calavera County Oral Testimony: 12/16/2010
WRIGHT	Tracey Wright Written Testimony: 12/3/2010
WSPA1	Catherine Reheis-Boyd, Western States Petroleum Association Written Testimony: 12/15/2010
WSPA2	Catherine Reheis-Boyd, Western States Petroleum Association Oral Testimony: 12/16/2010
YEAGER	Will Yeager Written Testimony: 12/10/2010
YESSNE	Gail Bates Yessne Written Testimony: 12/11/2010
YOUNGHARLAN	Harlan Young Written Testimony: 12/15/2010
YOUNGJ	Jonathan Young Written Testimony: 12/9/2010
YOUNGL	Lowell Young Written Testimony: 12/11/2010
YURMAN	Rich Yurman Written Testimony: 12/10/2010
ZELICHOWSKI	Dominik Zelichowski Written Testimony: 12/10/2010
ZIMMERMANK	Karen Zimmerman Written Testimony: 12/2/2010
ZIMMERMANM	Mitchell Zimmerman Written Testimony: 12/9/2010

B. AB 32 / CAP-AND-TRADE DESIGN

This section includes general programmatic and policy comments and responses about how the cap-and-trade program is and/or should be structured in the context of AB 32. AB 32 placed ARB in charge of ensuring that the State's greenhouse gas emissions are reduced to 1990 levels by 2020 and authorizes the Board to utilize market-based compliance mechanisms (e.g., a cap-and-trade program) to meet this goal. Major topics within this section concern development of the regulation; collaboration and coordination with other agencies; the level of the "cap" or allowance budget (i.e., maximum allowed greenhouse gas (GHG) emissions by all covered entities in each year; sections 95840–95841 and table 6-1 of the regulation); implementation, including program monitoring and adaptive management; treatment of different covered sectors; interaction of the regulation with the Low-Carbon Fuel Standard; cost-effectiveness; and potential linkage with Western Climate Initiative (WCI) partner states and provinces and other cap-and-trade programs (sections 95940–95943).

AB 32

General

B-1. Comment: Combine trading with direct regulation (now or in the future). (USFLAW)

> **Response:** We agree. ARB is pursuing both direct command-and-control regulations, such as, but not limited to, the low carbon fuel standard, advanced clean car regulation, stationary refrigeration regulation, and a market based cap-and-trade regulation to reduce GHG emissions. In addition, ARB has adopted a regulation entitled "Energy Efficiency and Co-Benefits Assessment of Large Industrial Facilities." We will use the findings of these assessments to identify additional measures that could be taken on a source-specific basis through direct regulation.

B-2. Comment: NextEra Energy supports the majority of the elements contained within the proposed regulation, including but not limited to the ability to use offsets to meet a compliance obligation; the establishment of cost containment mechanisms; banking of allowances; a three-year compliance period; the price floor; the cost containment reserve auction, the quarterly allowance auction; limited protection for economically disadvantaged industries; an emission threshold for applicability; a multi-sector program, and the placeholder for inclusion of voluntary renewable energy accounting under the cap and trade program. (NEXTERAENERGY)

> **Response:** Thank you for your support.

B-3. Comment: ARB must protect public health and require industries to pay the full cost of the pollution they emit. (AFFONSO)

Response: The regulation is designed to reduce GHG emissions in California, improve the environment, and protect public health. Covered entities must turn in allowances equal to their GHG emissions. The declining cap on emissions ensures that there will be emission reductions. The price of allowances will depend on the cost of available emission controls.

B-4. Comment: Include carbon fees to fund important programs. (CPC1)

Response: We considered alternatives to the cap-and-trade program, and implementing a carbon fee was one of the alternatives considered; however, we determined that a cap-and-trade program was more favorable. Details on why we chose cap-and-trade over a carbon fee can be found in Chapter IV of the Staff Report.

B-5. Comment: There are no comparisons given that show the people what our costs are today and what the costs and changes would be to us tomorrow with the implementation of AB 32. (SACREB)

Response: Appendix N of the Staff Report provides ARB's economic analysis that evaluated costs incurred to the general public as part of the implementation of the cap-and-trade regulation. Cost impacts on consumers would result from changes in energy prices. Households that consume less energy will be less affected by higher prices than those that consume more energy.

Voluntary Efforts/Early Action

B-6. (multiple comments)
Comment: The Sonoma County Water Agency supports the adoption of the proposed regulations for the Cap and Trade program. However, as we have discussed with ARB staff, we have two main concerns:

1. How will the Cap and Trade regulations impact voluntary compliance programs for GHG reductions, and in particular those administered by local agencies and special districts? Although we are not asking for specific amendments to the regulations at this time, we are preparing concepts and proposals for future revisions to the regulations to ensure full recognition and accounting for emissions reductions from viable, voluntary compliance programs.

2. ARB must ensure that the cap and trade regulations do not create an inadvertent windfall for utilities and fuel distributors who claim allowance credit for GHG emissions reductions that are actually resulting from the actions and accomplishments of voluntary local programs. That is, the county makes the investment in GHG reductions, and another entity is able to discharge their surrender obligation without actually making the investment and incurring the cost of the emissions reduction.

What the regulations do not accomplish is a framework to encourage, retain, energize and reward the many voluntary efforts in California to reduce carbon emissions. SCWA would like to work with ARB through the AB 32 implementation process to develop a clear set of policies, and potentially regulations, that accomplish the following goals:

- Support the development of a community-scale accounting protocol (GHG Accounting Protocol), which is consistent with regulatory and voluntary reporting requirements and frameworks, to assist local governments in the measurement of GHG emissions in their communities.
- Request that CARB become signatory to an MOU or formal partnership with ICLEI and others (U.S. EPA, The Climate Registry, etc.) to develop and adopt the Protocol.
- Develop a list of best practice measures for public-sector (local government) Programs.
- Assign CARB staff to serve on a high-level steering committee to provide strategic direction on the development of a community-scale emissions reduction protocol (GHG Reduction Protocol)—participate in regular meetings, assist in the development and implementation of a public engagement plan, assemble technical committees, determine reporting and inventory processes and concept development.
- Ensure consistency with the Western Climate Initiative's regional Cap and Trade program and work to inform or incorporate broader national/international standards as they pertain to local government participation in the Program. (SCWA)

Comment: It is unclear how businesses that have already undertaken early and voluntary GHG emission reduction actions will receive credit. (SDCHAMBER)

Comment: As the State of California transitions to a mandatory greenhouse gas emission reduction program, the Council believes it is critical to recognize early action taken by businesses and other entities to reduce emissions and to credit them for the prior investments that have been made to reduce emissions through the deployment of efficiency, renewables, and other measures. (BCFSE)

> **Response:** We recognize the benefits of voluntary GHG reduction programs. Subarticle 14, section 95990 includes a process for accepting early action offset credits from qualified existing offset projects. The regulation allows eligible offset credits and ongoing projects under protocols developed for four project types to transition into the compliance offset program. Projects using the offset protocols are subject to verification and enforcement requirements that are specified in the regulation. These proposed project types include: U.S. Forest Projects, Urban Forest Projects, Ozone Depleting Substances Projects, and Livestock Manure Projects. It should be noted that offset credits are only available from non-capped sectors. Many voluntary efforts reduce emissions from the electricity, natural gas, or transportation fuel sectors, which are capped. Also, the regulation requires that allowances distributed to utilities must be used for ratepayer benefit.

The benchmarking method used to support direct allocation of allowances is also designed to benefit capped entities that have already undertaken action to reduce GHG emissions.

B-7. Comment: The usage of recycled glass deserves early action credit since it meets all of the necessary qualifications. The regulations for the glass manufacturing sector should permit an early action credit of a three percent energy savings for each 10 percent of recycled content and an equivalent offset for carbonate raw material usage which would have otherwise been utilized. (OWENSIL)

Response: The glass manufacturing sector is subject to the cap, and any reductions achieved by an individual facility would result in that facility having to surrender fewer GHG allowances. Offset credits cannot be generated for activities that reduce emissions in capped sectors. Offset credits for those reductions would be double-counted within the cap-and-trade program. Therefore, offset credits can only be issued for activities that are not capped.

Emissions Levels/Targets/Forecasts

B-8. (multiple comments)
Comment: When considering the 2020 emission limit of 427 million metric tons of carbon dioxide equivalent ($MMTCO_2E$) of GHGs, what method of GHG accounting is used? (ASMMANDEVORE2)

Comment: When considering the 2020 emission limit of 427 million metric tons of carbon dioxide equivalent ($MMTCO_2E$) of greenhouse gases in conjunction with the Western Climate Initiative (WCI), will emissions leakage be considered? (ASMMANDEVORE1)

Response: The statewide 2020 emission limit of 427 $MMTCO_2e$ is based on the net amount of GHGs emitted to and removed from the air through forest sequestration of CO_2. The 2020 emission limit is California's 1990 emissions based on an inventory of the amount and type of GHGs emitted by different sources on an annual basis. The 2020 emissions limit was endorsed by the Board at its December 2007 hearing. California's program has been designed to minimize emissions leakage. As part of the regular program monitoring, ARB will monitor for potential leakage. Furthermore, as ARB proceeds to link with the Western Climate Initiative, potential emission leakage issues will be identified and addressed.

B-9. Comment: The regulation should contain a clear updated summary and accounting of emission reduction goals and contributions from various measures. Since there have been updates to emissions forecasts, necessary emission reductions to get to 1990 levels, and contributions from various measures, it would be useful to see all these numbers reconciled and summarized in a single place in the regulation. This would include an update to Table 2 of the Scoping Plan. (BP)

Response: We agree and released a status update on AB 32 Scoping Plan measures that includes revised GHG emissions reduction estimates for recommended measures in the Scoping Plan. This information is posted on ARB's website at: http://www.arb.ca.gov/cc/scopingplan/status_of_scoping_plan_measures.pdf.

B-10. (multiple comments)
Comment: The aim to return California's emissions to 1990 levels by 2020 lacks ambition, and does not respond to demands by developing countries facing climate change who are calling for wealthy states like California (that use a disproportionate amount of our global atmosphere related to global population) to reduce emissions much more radically. (CTW)

Comment: Please do your best to strengthen the Proposed California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms Regulations (LANEW)

Comment: Please make sure our GHG emissions are reduced by providing as low as possible caps for all GHG emitters, which are reduced annually to reach scientific targets. (DISENHOUSE)

Response: AB 32 authorizes ARB to implement a comprehensive, multi-year program to reduce GHG emissions in California. This statute includes the goal of reducing California's GHG emissions to 1990 levels by 2020. ARB's regulations must meet all AB 32 requirements, balancing technical feasibility, cost-effectiveness, improving public health, attaining ambient air quality standards, and many other objectives. We believe that cap-and-trade regulation appropriately balances these objectives.

Cap-and-Trade

General

B-11. Comment: We support your idea to hire an expert to look at the impact of the regulation on the state energy markets. (WSPA2)

Response: Thank you for your support.

B-12. Comment: We commend CARB for designing the Cap and Trade regulation with numerous flexible cost-containment mechanisms, in particular banking, rolling three-year compliance periods, and offsets and linkage. (CLIMATEWEDGE)

Response: Thank you for your support.

B-13. Comment: Cap and trade models are not successful prophylactic measures and have proven to be ineffective tools for phasing out carbon use. Pollution trading is an ineffective air quality policy with the arguable exception of the Acid Trading Program. Due to over allocation of allowances, low carbon prices, fraudulent transactions and banking (which may result in short term reductions followed by a spike in emissions when banked credits are utilized), pollution trading programs do not significantly reduce air pollution. Additionally, pollution trading often does not result in emissions reductions because of difficulty monitoring and enforcing emission reductions. (CRPE1)

> **Response:** We do not agree that a well-designed cap-and-trade regulation is an ineffective tool at reducing GHGs. The declining cap on emissions ensures there will be emission reductions.
>
> We used several years' worth of emissions data to determine the number of allowances that would be made available. It is unlikely that the California market will be over allocated. Banking is a necessary design feature intended to prevent price variability. It also provides an incentive for covered entities to make early reductions.
>
> We will implement a market tracking system that will track and monitor compliance instruments (allowances and offset credits). The cap-and-trade regulation also has provisions that provide market oversight. These provisions involve information disclosures to assist in monitoring the market and prohibitions on trading activities that involve fraud, reporting false or misleading information, misrepresentations, and other commonly used techniques used to manipulate markets.
>
> The premise that pollution trading programs do not significantly reduce air pollution is contradicted by experiences in other programs. The RECLAIM program in the South Coast Air Quality Management District has achieved reductions well beyond original expectations and continues to show increased reductions, including in areas adversely impacted by pollution and consistent with the ozone SIP for the South Coast Air Basin. As noted, the federal Acid Rain program has also gone well beyond the original emission reduction estimates and has lowered control costs over what would otherwise have occurred under a command-and-control system. In both cases, as in other market-based regulatory systems, adjustments have been made as problems are identified, and cost-effective emission reductions continue to occur.

B-14. Comment: It is important that the cap-and-trade rule encourage innovations that convert GHGs to stable non-GHG forms. Calera urges ARB to revise the proposed Cap and Trade rule to encourage out-of-state sources to reduce emissions through any means, including conversion of greenhouse gases to non-GHG forms. Specifically, add the following definition: "'Carbon Conversion' means the generally permanent conversion of carbon dioxide to non-GHG forms, such as carbonate, calcium carbonate, magnesium carbonate, bicarbonate, and other stable chemicals that are not greenhouse gases and will not readily revert to GHG forms." Also modify the definition of "greenhouse gas emission reduction" as follows: "Greenhouse gas emission reduction" or "GHG emission reduction" or "greenhouse gas reduction" or "GHG reduction" means a calculated decrease in GHG emissions relative to a project baseline over a specified period of time and shall include chemical conversion of greenhouse gases to stable non-GHG forms." (CALERACORP)

Response: No response necessary.

B-15. Comment: I recommend putting a cap on the number of "tradable" permits or exceptions. It doesn't make sense to allow one company to pollute as much as it can while other companies scrape their levels back and trade allowances with the major polluter. In particular, the largest polluters should have to reduce emissions or pay fines, rather than grab someone else's allotment. (SIRCAR)

Response: The commenter is misguided in how the covered entities can 'pollute' under the program. The tradable permits under the cap-and-trade program are issued in a number designed to ensure we get the reductions needed to reach the AB 32 target. The prices paid for tradable permits will reflect the cost of direct reductions in emissions. Emitters can observe this price and determine whether it is cheaper to purchase permits or make reductions. Even recipients of a direct allocation will have an incentive to make reductions so they could sell permits to others that face higher compliance costs. Nothing in the cap-and-trade regulation allows larger emitters to emit more emissions than allowed by air permits issued by the local air districts. Having the ability to purchase extra allowances does not equate to unlimited rights to emit.

Transparency

B-16. Comment: Data should be provided in a database download dump that would ideally be in the native database language SQL. Alternatively, Excel or CSV spreadsheets should be published for each dataset, with a unique identifier for each installation, company, etc. that is used throughout the dataset, so that the dataset can be imported into a database. Our recommendations for provisions of public data in relation to the trading scheme are as follows:

- All relevant data should be made available at an installation level. This enables the maximum levels of transparency;
- Company ownership of installations, including parent company ownership, should be published;
- Installations should be grouped and identified by sectors of the economy at the most disaggregated level possible, i.e. by product type or service;
- Data about installation level emissions (current and historic) and any free allocations should be released;
- The use of offsets for compliance should be recorded separately from the use of allowances;

- Details of the projects generating the offsets used for compliance at an installation level should be made publicly available;
- All benchmarks used for free allocations, including adjustments for variations in production levels, should be made public;
- The total volume of emissions issued by auction and held in reserves should be regularly published (at least once a quarter);
- Volumes of allocations removed in response to voluntary uptake of green tariffs or through voluntary cancellation should be published regularly (at least annually);
- Changes in scope between compliance periods should be clearly labeled and made public so that an accurate picture of aggregate emissions over time can be developed. If new entrants are not clearly labeled in order that they may be disaggregated from existing participants, aggregate data becomes distorted and of limited use in analysis of performance; and
- Any transactions between installations that involve the transfer of flue gases for fuel, accompanied by allowances, should be recorded and made publicly available. This does not happen currently in Europe and makes analysis of performance under the scheme unnecessarily difficult. (SANDBAGCC)

  Response: We agree that it is important to have public data readily available in a user-friendly format. Currently, mandatory emissions reporting data can be downloaded from the ARB website. Beginning in 2012, the market tracking system will compile information on holders of compliance instruments (allowances and offset credits) and trading of compliance instruments among market participants. We will ensure that auction and trade data information is easily accessible from the ARB website. Benchmarks used for free allocations are included in the regulation.

Collaboration/Coordination

B-17. Comment: There are several provisions in the proposed regulations and protocols that may require support by CAL FIRE or warrant further exploration with the Board of Forestry and Fire Protection. CAL FIRE suggests clarification or incorporating into the regulation language that directs or allows ARB to work with CAL FIRE and the Board of Forestry and Fire Protection to address these needs. (DFFP1, DFFP2)

> **Response:** We agree that it would be good to work with our sister State agencies throughout implementation of the cap-and-trade regulation and plan to do so on a number of provisions of the regulation. For example, we plan to work with CalFire and the Board of Forestry and Fire Protection as we implement the U.S. Forest Protocol.

B-18. Comment: There should be coordination and consistency between California's program and federal regulations. Businesses should not be asked nor expected to use different protocols and inventory formats for GHG reporting. (SDCHAMBER)

Response: We agree that it would be desirable to have businesses meet State and federal requirements using one set of protocols. As stated in Resolution 10-42, the Board directed the Executive Officer to work with U.S. EPA on the development of a federal regulatory framework to grant delegation or equivalency to California's climate change program where appropriate. ARB is aligning the GHG reporting regulations with federal requirements. We are also working toward a unified reporting system to satisfy both State and federal requirements while minimizing duplicative or conflicting reporting obligations for facilities subject to both rules.

B-19. (multiple comments)
Comment: SCAQMD recommends that there be a report to the CARB Board in three months regarding how local air districts are being utilized in various aspects of the program, including emission verification, offset verification, and protocol development. This can help ensure better collaboration in the future and enable appropriate use of local air district resources and expertise. (SCAQMD1)

Comment: The draft regulation specifically prohibits local air districts from performing multiple functions related to the cap on Greenhouse Gas Emissions compliance program. However, SCAQMD has staff resources and expertise that can help ensure successful implementation of the program and other stationary source programs under AB 32. The potential conflict of interest issues applicable to for-profit businesses do not exist for a local air quality agency like SCAQMD. Our organization is a sister regulatory agency with public health as the primary motivation. We are not for-profit, and would approach any function with the motivation to do what is right, not to generate income or ensure repeat business. We request the ability to perform multiple functions in the cap and trade program, including verification of emission reports. (SCAQMD1)

Response: We agree that districts can play an important role in helping ARB implement the cap-and-trade regulation. However, we do not believe the report suggested by the commenter is necessary. In Resolution 10-42, the Board directed the Executive Officer to develop amendments to the cap-and-trade regulation to provide for air district verification of offsets. The regulation has been amended to reflect this.

In addition, Board Resolution 11-32 directed the Executive Officer to partner with the air quality management districts and air pollution control districts in the implementation of the cap-and-trade regulation, including, but not limited to, an evaluation of the impacts of the cap-and-trade program on industrial source greenhouse gas permitting and implementation of the Adaptive Management Plan. The Board further directed the Executive Officer to report back periodically to the Board on the nature and extent of this partnership, with the first report due in the first quarter of calendar year 2012.

Working Group/Advisory Group

B-20. (multiple comments)
Comment: The Board should establish working groups of covered entities to assist staff in identifying potential compliance and market operational problems that should be addressed before the program commences. (CCC, MAZOWITA)

Comment: We ask that cost implications be recognized and also for a panel to be set up to monitor these kinds of costs and agriculture have a seat at the table because we're the ones paying the bill. So hopefully we can be a part of the panel. (CCGG)

> **Response:** We agree that we need to carefully monitor industry progress toward compliance with the regulation, as well as the operation of the markets. However, we do not see the need for working groups of covered entities, as suggested by the commenter. As discussed in Resolution 10-42, the Board directed the Executive Officer to hold public consultations over the next year to identify potential obstacles to compliance and, as necessary, incorporate or enhance compliance assistance mechanisms into the program. The Board also directed the Executive Officer to contract with an independent entity with appropriate expertise to monitor and provide public reports on the market's operation, including auctions and reserve sales, on a quarterly basis and recommend appropriate action, which could include taking corrective action prior to the next auction, adding future allowances to the allowance reserve or future auctions, or temporarily suspending trading in the market. We will continue to meet with stakeholders as the regulation is implemented and update the Board on progress in implementing the regulation.

B-21. Comment: The resolution should provide for periodic reports back to the Board on the availability of necessary regulatory tools and guidance, the results of the independent market evaluation, the determination of the equivalency of California's program with EPA regulations, and the identification and resolution of potential compliance and market operational problems identified by the recommended covered entity troubleshooting work group. (CCC, MAZOWITA)

> **Response:** We agree that periodic reports should be provided to the Board on the operation of the cap-and-trade program. As discussed in Resolution 10-42, the Board directed the Executive Officer to update the Board annually on the status of the cap-and-trade program. In addition, the Board directed the Executive Officer to hold public consultations over the next year to identify potential obstacles to compliance and, as necessary, incorporate or enhance compliance assistance mechanisms into the program. While the resolution language does not specifically mention all of the specific areas suggested by the commenter, we believe the broad language in Resolution 10-42 provides for reports to the Board on any issues of concern, including those mentioned by the commenter.

B-22. (multiple comments)
Comment: We think that it might be useful to have a joint CARB and air district implementation working group for cap and trade so we can discuss with CARB staff steps of the program as it moves forward and discuss and resolve issues. We've used this for other programs, and it's been quite successful. (BAAQMD)

Comment: An advisory committee with participation by a CARB Board member would be an effective tool to further enhance the collaborative partnership that SCAQMD and other air districts would like to forge with CARB on AB 32 programs. We recommend the following Resolution language to improve on-going coordination with local air districts:

Add: BE IT FURTHER RESOLVED that the Board directs the Executive Officer to establish an Advisory Committee with air districts to facilitate their involvement in implementation of this regulation and other AB 32 programs. The Executive Officer is directed to report back to the Board in three months regarding progress for this effort. (SCAQMD1, SCAQMD2, SCAQMD3)

Comment: To help ensure more productive collaboration in the future, CAPCOA suggests a report to the CARB Board in three months regarding how local air districts are being utilized in various aspects of the program, such as emission verification. We also respectfully suggest that the Board consider whether an advisory group with participation by a Board member, would enhance the collaborative process. (CAPCOA1)

> **Response:** As discussed in Resolution 10-42, the Board directed the Executive Officer to establish a Board Member-facilitated dialogue with CAPCOA regarding involvement of the districts in the implementation of the cap-and-trade regulation, development of compliance offset protocols, and other AB 32 programs. We believe this will accomplish the goals of the working group suggested by the commenter, as well as the language in Board Resolution 11-32 that directed the Executive Officer to partner with the air quality management districts and air pollution control districts in the implementation of the cap-and-trade regulation, including, but not limited to, an evaluation of the impacts of the cap-and-trade program on industrial source greenhouse gas permitting and implementation of the Adaptive Management Plan. The Board further directed the Executive Officer to report back periodically to the Board on the nature and extent of this partnership, with the first report due in the first quarter of calendar year 2012.

Public Process

B-23. Comment: Rural county governments have largely felt excluded from the process because of ARB's focus on urban and suburban needs. Participating in ARB workshops is challenging for rural citizens due to distance and the lack of availability of broadband in rural communities. If the Cap and Trade program will truly benefit California citizens in the long run, we urge you to initiate an outreach program in rural areas to provide education and the kinds of thoughtful discussion opportunities that have thus far been lacking in the AB 32 implementation process. We have seen countless jobs leave rural communities, and while ARB touts the growth of the green job market, we have yet to see these jobs readily available in rural counties. Citizens in rural areas are concerned that cap and trade will exacerbate unemployment while raising costs for energy, housing, and other goods and services. Many business owners see the cap and trade program as just another regulatory scheme that will cost them money and possibly force them out of state, or worse, out of business entirely. (RCRC)

Response: The rule development process provided ample opportunity for input from all California citizens, including residents and governments of rural counties. As discussed in Appendix D of the Staff Report, we held over 30 public workshops during the development process. These meetings were also available via webcast. In addition, we maintained an ARB Public Meetings Webpage, where staff made available all workshop materials and comments posted by stakeholders on program options. Rural residents that were unable to attend workshops in person or by webcast had the opportunity to submit comments in writing, or by contacting ARB staff by phone or electronic mail. For these reasons, we do not believe that an outreach program specific to rural areas is needed.

Regarding the economic impacts of the regulation, we analyzed the potential impacts on businesses in detail using two different economic models. Based on these analyses, we made an initial determination that the regulation would not have a significant statewide adverse economic impact directly affecting businesses and little or no impact on the ability of California businesses to compete with businesses in other states.

B-24. (multiple comments)
Comment: The Board's resolution should commit to provide for one or more additional public hearings, or to reopen the record, prior to the commencement of the program, to enable stakeholders to comment further as more information becomes available regarding key program components. (CCC, MAZOWITA)

Comment: An incomplete regulation will exacerbate an already difficult economy and will create an uncertain regulatory environment that will discourage economic growth and future investment. It is unlikely that several of these pending issues will be resolved before year's end. With a 2012 implementation date, CARB must fill in the blanks on several of these missing elements. We urge CARB to implement any changes via an open forum, involving stakeholder input and public comment. If CARB intends to utilize the 15-day notice update process for current placeholder language, it's important they keep stakeholders apprised of any and all changes throughout this process. Stakeholders must have the opportunity to comment on the cumulative impact of all decisions prior to the market opening in 2012. We also urge CARB to include a periodic review process for the Cap and Trade regulation. (CALCHAMBER1)

Response: The rule development process provided ample opportunity for input from interested stakeholders. As discussed in Appendix D of the Staff Report, we held over 30 public workshops during the development process. Participation was possible at these workshops in person or via webcast. In addition, we maintained an ARB public meetings web page, where staff made available all workshop materials and comments posted by stakeholders on program options. Regarding proposed modifications to the original proposal, Resolution 10-42 committed staff to conduct one or more workshops on the proposed modifications and to provide the opportunity for public comment before the regulatory language was released for the formal 15-day public comment period. Staff did that and is also committed to providing continual public updates, with opportunities for stakeholder comment, on the implementation of the regulation. We also changed the compliance date from January 1, 2012, to January 1, 2013, to provide additional time to prepare for implementation of the regulation.

Implementation

B-25. Comment: California industry is faced with State, local, and federal requirements for air emissions that threaten to conflict, duplicate, or otherwise increase costs above that necessary to achieve our individual and collective policy goals. The current political and legal situation is confusing, and entities are struggling to predict and plan for what may be coming in the next years. A policy statement from CARB that recognizes the situation and puts a high priority on addressing these questions to protect the California economy would be welcome and provide some confidence that CARB will not proceed in a manner that puts California industry at risk. For example, we recommend that CARB resolve to modify the timeline, content, and implementation strategy of the state cap and trade program to avoid these excess costs and burdens. (CMTA1, AB32IG)

Response: We developed the cap-and-trade regulation recognizing the importance of achieving mandated GHG reductions in the most cost-effective manner possible. We analyzed the potential economic impacts on industry, as discussed in Chapter VIII and Appendix N of the Staff Report, and designed the cap-and-trade regulation to minimize the costs to industry while maximizing the benefits for California's economy. Based on the results from two economic models, the Executive Officer made an initial determination that the regulation would not have a significant statewide adverse economic impact directly affecting businesses, and little or no impact on the ability of California businesses to compete with businesses in other states. In addition, as discussed in Resolution 10-42, the Board directed the Executive Officer to hold public consultations over the next year to identify potential obstacles to compliance and, as necessary, incorporate or enhance compliance-assistance mechanisms into the program. The Board also directed the Executive Officer to work with CPUC, CEC, CAISO, and other interested parties to monitor the proposed cap-and-trade program, including the effect of the cap-and-trade program on the State's energy markets, and to monitor to the extent feasible the ability of affected entities to pass on costs. For these reasons, we do not believe that it is necessary to modify the timeline, content, and implementation strategy as suggested by the commenter. Nevertheless, the compliance start date was changed from 2012 to 2013, to ensure that all the regulatory elements are in place and fully functional.

B-26. Comment: We are concerned that CARB has not yet been able to confidently propose the details required to understand and implement the cap and trade program. Many of the tools, provisions, and methods still being developed by CARB will provide crucial information for companies planning for future operations, capital projects, supply and distribution, etc. There is no indication that the information will be forthcoming in advance of the last quarter of 2011, mere months before start of the market in 2012. The 15-day update process to fill-in these blanks will be developed with staff and the full implications of all the decisions will not be knowable until very late in the year. We are concerned that the public will not have a meaningful opportunity to comment on the total impact of all allocation decisions prior to market opening in 2012. (AB32IG)

Response: The compliance start date was moved from 2012 to 2013 to ensure that all the regulatory elements are in place and fully functional.

B-27. Comment: The Cap and Trade regulation, as proposed, should be scaled back, implemented slowly and be flexible to ensure that California's businesses do not suffer serious economic or other unintended consequences as a result of this regulation. (SDCHAMBER)

Response: We disagree that the cap-and-trade regulation should be scaled back. We analyzed the potential economic impacts on industry in detail, as discussed in Chapter VIII and Appendix N of the Staff Report. Based on the results from two economic models, the Executive Officer made an initial determination that the regulation would not have a significant statewide adverse economic impact directly affecting businesses and little or no impact on the ability of California businesses to compete with businesses in other states. Regarding flexibility, the major feature of the cap-and-trade regulation is that it provides more flexibility than traditional regulatory approaches.

B-28. Comment: Implementation of the Cap and Trade program should be deferred if necessary rules and infrastructure to enable entity compliance are not in place in a timely manner. WPTF proposes a provision in the cap and trade regulation or in the resolution that requires ARB to develop and adhere to a clear schedule for development of the rules, linkages and infrastructure necessary for implementation and compliance by capped entities, and that provides an automatic deferral of the start date for the cap and trade program if the schedule is not met. (WPTF)

Response: The compliance start date was moved from 2012 to 2013 to ensure that all the regulatory elements are in place and fully functional. We have initiated activities to develop the necessary rule implementation infrastructure for the regulation, including a market tracking program to trade allowances and offsets; contracts for an auction services provider; a financial services provider; and a market monitor. We are also committed to providing continual public updates, with opportunity for stakeholder comment, on the implementation of the regulation.

B-29. Comment: CARB has performed extensive re-analysis of the business as usual projection for 2020 taking into account the downturn in the economy, reduction measures that are now moving forward, as well as those reduction measures expected to occur in the future. This new projection leaves 18 $MMTCO_2e$ that must be reduced, presumably by the cap and trade program. However, CARB is continuing to design a cap and trade program to reduce approximately 30 $MMTCO_2e$. The Sanitation Districts recommend that CARB take advantage of the smaller reductions needed in the proposed program to design a more modest cap and trade program that can be ramped up in the future after CARB gains experience in operating such a program. The new projections also indicate a reduced urgency in getting a market up and running, so there is more time for staff training, establishing the necessary tools to run the program, beta testing and market simulations. We believe that taking this approach will ultimately lead to a more certain market that will serve as a solid foundation when more sectors are brought into the program in the future, as well as allowing more time to work out linkages to other cap and trade programs. Our fear is that proceeding too rapidly without a proper foundation will lead to an unstable market and inflated allowance prices, with their negative "trickle-down" effect. (LASD1)

Response: The cap-and-trade regulation was designed to cap emissions and put a price on carbon. The program will ensure that California meets the 2020 goal, including emission reductions that are not obtained from direct measures. At this time, reductions from direct measures in 2020 are simply estimates. Obtaining emission reductions from measures such as energy efficiency depend on continual funding, as well as successful implementation of efficiency programs. The regulation is designed to achieve at least 18 $MMTCO_2e$, rather than the 30 MMT mentioned by the commenter. Regarding the concern that we are proceeding too rapidly, we moved the compliance start date from 2012 to 2013 to ensure that the regulatory elements are in place and fully functional.

B-30. (multiple comments)
Comment: The Sanitation Districts are very concerned that implementation of the proposed program is proceeding at too rapid a pace which could lead to higher than anticipated allowance prices. The trickle-down effect of this will negatively impact California's downturned economy further. The Sanitation Districts suggest that CARB take a slower, more modest initial approach to implementing a cap and trade program, allowing time for beta testing the market mechanisms, allowing time for learning from mistakes, building in more frequent overall program evaluation, creating dispute resolution procedures outside of the court system, allowing the development of a robust offset market and establishing the necessary linkages to allow for a healthy trading market. (LASD1)

Comment: We are concerned that the proposal remains significantly incomplete and lacks sufficient regulatory guidance for timely compliance when the AB 32 program commences. Much of the unfinished business includes material components of the program, including the allocation of allowances to the power, fuels and industrial sectors; selection of emission factors for various source types (particularly as the ARB intends to use both higher-tier emission factors than EPA uses for its reporting program as well as highly-conservative missing data provisions); the allowance tracking system; the auction system; the registration process; and various other critical components. (CCC, MAZOWITA)

> **Response:** Benchmarks and allocation to all sectors are described in the regulations. In addition, the compliance start date was moved from 2012 to 2013 to ensure that all the regulatory elements are in place and fully functional. We have initiated activities to develop the necessary infrastructure for the regulation, including a market tracking program to trade allowances and offsets; contracts for an auction services provider; a financial services provider; and a market monitor.

Program Monitoring

B-31. (multiple comments)
Comment: It is imperative that the regulation provide sufficient flexibility to review and make corrections as needed. This will afford stakeholders and the public an opportunity to remain engaged with the program and offer insight on how to improve elements of the program moving forward. (NRDC1)

Comment: The Cap and Trade regulation should include a requirement for periodic review and update. AB 32 requires a review of the Scoping Plan in 2013, but it is unclear whether this requirement includes a review of the cap and trade regulation. The resolution language should also include examples of issues to be included in the review. (BP)

Comment: Built-in review of the program's effectiveness is needed. As with all new programs, especially one this complicated, it is necessary for regular reviews of its effectiveness. WIRA recommends the regulation, or adopting resolution, contain language requiring periodic public reviews by the Board on the various elements of the programs to ensure that it is working as intended and to evaluate any unintended consequences. (WIRA1)

Comment: The regulation should provide for program review and possible modification. It is extremely important, both for the sustainability of the program and its relevance as a model for other programs at the State and federal level, that California gets the design right. We believe it is important that the regulation provide for program monitoring and possible modification. Key economic and program indicators should be monitored, and a periodic program review mandated so that any inadvertent problems with the program can be corrected before major damage is done to the economy. The provisions for program monitoring and review in the recently adopted Renewable Energy Standard would be an appropriate model for this regulation. (WPTF)

Comment: The proposed rule is very complex and there are still many unresolved issues. The uncertainty in the implementation, possible implications on the economy, and complex compliance requirements argue for a review period where progress and issues can be identified and addressed. ARB should implement a review period at the end of the second year of the first compliance period (by 1/1/14) to review the program and identify areas of concern. This review should include monitoring of key indicators using criteria developed by staff and Cap and Trade participants. The review period should conclude with a peer-reviewed report presented to ARB Board members. (WSPA1)

Comment: NCPA agrees that ongoing monitoring of the Program is important. While CARB has stated that it is "committed to review and revise policies, protocols, and procedures as more information becomes available," the proposed regulation itself is devoid of any references to the form and procedure for this monitoring, nor does it address the manner in which the necessary policy and procedure revisions will be carried out. Since the ISOR contemplates CARB conducting evaluations in advance of each of the compliance periods with sufficient time to adjust the Program if warranted, NCPA recommends that the proposed regulation be revised to add language that would address a formal review process for the Program. Each review would take place at least once each compliance period, with the first review to start mid-way through the first compliance period. Regulated entities must have some assurances regarding the viability and stability of the underlying program. That is especially important in the context of the new cap-and-trade program, where the State is dealing with the provision of essential services in a potentially volatile market. Accordingly, the proposed regulation should also include provisions that would govern its review and necessary corrective actions. Such language would prescribe the review schedule, as well as the range of issues and criteria that would be considered during the review, and provide a vehicle to address necessary corrections. Such a review process would better enable CARB to develop criteria and processes by which to undertake future adjustments, if necessary. Furthermore, ideally, as California links with the WCI partner jurisdictions, the ongoing review of the State's own program would serve to support the administrative record that would be developed for purposes of linking rulemakings contemplated in sections 95940, 95941, and 95942. (NCPA1)

Comment: Monitoring of the program will be crucial to its success. Given limitations on resources available to CARB, it would make sense to involve entities such as transit districts, air districts, and local governments as much as possible in the implementation and monitoring of the program. (ASMDICKINSON)

Comment: We strongly urge CARB to clearly establish and communicate to the market the conditions under and process by which the rules of the Cap and Trade system may be adjusted in the future. (CLIMATEWEDGE)

Comment: The Staff Report (at II-56 and following) discusses monitoring and reviews of the Cap and Trade regulation. However, this is not set out in the regulation itself. The Cap and Trade regulation should contain a provision setting out the features that will be reviewed every three years to determine whether the regulation needs to be revised, and which sections may be revised. Even if these provisions are broad, they will provide useful indications of possible changes. Apart from urgent changes, a notice period of at least one year should be given for all changes to the Cap and Trade regulation that will require significant changes to the behavior of covered entities. (SCPPA1)

Comment: WIRA recommends the proposed regulation, or adopting resolution contain language requiring periodic public reviews by the Board on the various elements of the programs to ensure that it is working as intended and to evaluate any unintended consequences. (PMTPETRO1)

> **Response:** We do not believe it is necessary to include regulatory language to require regular updates. However, we are committed to regular reviews of the implementation of the regulation, periodic updates to the Board, and proposed modifications to the regulation, as needed. As discussed in Resolution 10-42, the Board directed the Executive Officer to update the Board annually on the status of the cap-and-trade program. We believe the broad language in Board Resolution 10-42 provides for reports to the Board on any issues of concern.
>
> Further, we agree that we need to carefully monitor industry progress toward compliance with the regulation, as well as the operation of the markets. We have initiated activities to develop the necessary rule implementation infrastructure for the regulation, including a market tracking program to trade allowances and offsets; contracts for an auction services provider; a financial services provider; and a market monitor. We are also committed to providing continual public updates, with opportunity for stakeholder comment, on the implementation of the regulation.

B-32. Comment: CARB should build in an explicit adaptive management process to adjust the free allocation to the industrial sector based on specified evaluation metrics. As a condition of free allocation, CARB should require industrial sector emitters to provide detailed information on production input costs and revenue to enable a more rigorous, analytical understanding of the extent to which free allocation protects consumers and prevents leakage, or to what extent allocation needs adjustment to avoid windfall profits. This information would be kept confidential at the individual firm level, though it could be released at the sector level so that proprietary information would not be compromised. (KUSTIN10, EBERHARD)

> **Response:** ARB will continue to monitor leakage during the implementation process. Should ARB identify that leakage is occurring, we will develop appropriate responses to rectify it. We have included features in the cap-and-

trade regulation, such as periodic updating of leakage risks to adjust or phase out free allocations. We will work with the California Public Utilities Commission to ensure that the proposed allowance value directed to the electric distribution utilities is used for the benefit of residential, commercial, and industrial ratepayers that might otherwise face indirect costs from implementation of this regulation, and for the purposes of AB 32.

As noted in the Staff Report, we are committed to monitoring how covered sectors, especially those that receive free allocation, address carbon costs once the program is in place. In addition, for allocation purposes, we are collecting product data from almost all sectors at risk for leakage. The data set from this collection will also serve as a key monitoring step in detecting leakage. During program implementation, we will assess whether it is necessary to collect such confidential business information as production input costs and product revenues to determine if businesses incur windfall profits as a result of free allocation. We anticipate that the combination of rigorous benchmark formulas and basing the free allocation on production data should ensure that free allocation for leakage purposes does not result in windfall profits or a sustained oversupply of free allowances.

Per Resolution 10-42, we will continue to review information concerning the emissions intensity and trade exposure of different industries in California. We will recommend changes to the Board on leakage risk determinations, if needed, prior to the initial allocation of allowances for the first compliance period starting in 2013 for industrial sectors not identified in Table 8-1 of the cap-and-trade regulation. And prior to the initial allocation of allowances for the second compliance period starting in 2015 for industries identified in Table 8-1 of the cap-and-trade regulation. We will update the Board annually on the status of the cap-and-trade program, including, to the extent feasible, information on shifts in business activity that may result in emissions leakage and changes in market share for covered entities and sectors.

Additional Efforts

B-33. Comment: All participants must realize that a cap and trade system does not replace our State's other GHG mitigation policies. Thus, we need to stay the course and expand implementation activities related to energy efficiency and other clean energy policy initiatives. This particularly includes public benefits charge funding for energy efficiency programs. (CEEIC)

Response: The cap-and-trade program is a key element of an overall strategy to reduce California's GHG emissions to 1990 levels by 2020. This market-based program is used to supplement, rather than replace, direct regulation approaches. It is also designed to work in concert with other measures, such as standards for cleaner vehicles, low-carbon fuels, renewable electricity, and energy efficiency. The program will also complement and support California's existing efforts to reduce criteria and toxic pollutants.

Additionally, as discussed in Resolution 10-42, the Board directed the Executive Officer to work with the California Public Utilities commission and publicly owned utilities to ensure that the proposed allowance value could include investment in energy-efficiency programs and renewable energy projects that achieve environmental and public health co-benefits.

Delay Action

B-34. (multiple comments)
Comment: SCE supports a delay in implementation of the Cap and Trade program for a full evaluation of the market rules. (SCE1)

Comment: ARB should revise the proposed rule to ensure that no reductions in GHG emissions are forced to occur before January 1, 2015. This recommendation is not sought for purposes of delay. It is sought so that the program can be effectively implemented and the costs reduced by appropriate planning. There is no emergency that justifies a different approach. Despite dire warnings about the consequences of delay, it is clear that California, acting on its own, is not going to change the imminence of any such impacts. It is better to systematically plan for these changes than to induce an economic emergency. (HOR)

Comment: We think that ARB should consider delaying implementation for the smaller emitters less than 100,000 tons per year until 2015 to allow the regional markets to develop or the global markets and to become firmly established and viable. (INDENVASSOC)

Comment: ARB should consider delaying implementation of the regulation for smaller emitters (<100,000 TPY) until 2015 to allow regional or global markets to be established and viable for broader industry participation. (SOLARTURBINES1)

Response: We will not delay compliance for smaller sources until 2015. We modified the regulation to begin the compliance obligation in 2013. It is important to include these smaller sources in the early years of the program to provide a robust market and for linkages to the Western Climate Initiative. We will initiate all elements of the program throughout 2012, including establishing market infrastructure, conducting trainings, holding auctions, and developing linkages with partners in the Western Climate Initiative. These proposed changes ensure that all essential elements of the program are developed and tested before we move into the first year of compliance in 2013. This provides the market with certainty about the program's direction as it starts over the next 18 months.

We disagree with the comment that the cap-and-trade approach instituted in Europe is a failure. However, that there may be lessons to be learned from the

European Union (EU) Emissions Trading Scheme (ETS). A recent press release claims that cap-and-trade has failed to reduce GHG emissions in Europe. The claim appears to be misguided given that the EU ETS are all reporting substantial GHG emission reductions. The claim comes from recent work that shows that the carbon embedded in international trade flows has increased substantially since 2020. Some initial analyses have tried to examine the net balance of embedded carbon in trade flows, which show that for the key European countries and the EU as a whole, the net trade impact is a net increase in embedded GHG emissions in trade flows. While domestic emissions are declining in these countries, the net embedded emissions in trade flows more than compensate for the domestic reductions. Note that this circumstance does not mean that cap-and-trade is a failure in Europe. The emissions covered by cap-and-trade are declining. The emissions not covered by cap-and-trade are increasing. Cap-and-trade is not inducing the increase in the embedded carbon as is evidenced by even larger increases in net embedded carbon estimated for the U.S. (which has no cap-and-trade, and little in the way of climate initiatives at this time). The studies of embedded carbon explicitly make the point that cap-and-trade is not inducing this embedded carbon issue. So, the claim that cap-and-trade is a failure in Europe is not really true. Information about the EU experience relating to both successes and challenges was considered during the development of the California cap-and-trade regulation.

Economic Harm/Burden

B-35. Comment: The program incurs an administrative cost with no practical impact. (MSCG2)

Response: We are unclear why the commenter believes the cap-and-trade regulation will have no impact. Under the regulation, GHG emission will be capped and reduced by 2020. We developed the regulation to minimize administrative costs associated with implementation and maximize emission reductions. In the Staff Report, we describe an auction design based on a set of objectives that minimizes administrative and transaction costs to participants.

The market tracking system (MTS) will record information about the holders of compliance instruments and trades of compliance instruments among market participants. The primary goal of the MTS will be to support the effective implementation of the cap-and-trade regulation and to reduce the costs and administrative burden associated with long-term cap-and-trade responsibilities.

In addition, revisions to the Mandatory Reporting of Greenhouse Gas Emissions Regulation are intended to align California's reporting requirements with federal reporting rules recently enacted by U.S. EPA. We are working toward a unified reporting system to satisfy both State and federal requirements while minimizing duplicative or conflicting reporting obligations for facilities subject to both rules.

B-36. Comment: November's federal elections have all but guaranteed that there will be no effort to establish a federal cap and trade market nationally. Given this development, California's efforts to implement a cap and trade will only add to the burden of California businesses and families struggling under a continuing recession. Despite assurances to the contrary, we believe that California's Cap and Trade will be unique in the U.S for some time, as evidenced by continued shrinking of the Western Climate Initiative's member states. California, by going it alone, risks grave economic harm and risks recovery from the recession if there are no other strong market partners. California jeopardizes the progress it has made as a leader in air quality and as a supporter of green business should its rush to implement an incomplete regulation. (CALFP1)

> **Response:** We analyzed the potential economic impacts on industry in detail, as discussed in Chapter VIII and Appendix N of the Staff Report. Based on the results from two economic models, the Executive Officer determined that the regulation would not have a significant statewide adverse economic impact directly affecting businesses and little or no impact on the ability of California businesses to compete with businesses in other states. The regulation was designed to address potential leakage concerns by providing free allowances to energy-intensive trade-exposed sectors.
>
> We will continue to work with our partners in the Western Climate Initiative to identify, evaluate, and implement policies to reduce GHG emissions, including the design and implementation of a regional cap-and-trade program.

Cap/Allowance Budget

B-37.

Comment: The "cap" excludes agriculture, biofuels and bioenergy, which are significant sources of GHG emissions. Treating biofuels and bioenergy as zero emissions and excluding them from the cap is not supported by the best science or ARB's own analysis and it violates AB 32's mandate to achieve the maximum reductions. (CRPE1)

> **Response:** We believe that the regulation supports the mandates outlined in AB 32, including technological feasibility and maximizing the amount of GHG reductions. The commenter is correct in that agriculture is an uncapped sector and does not have a compliance obligation. Under the regulation, agriculture will be encouraged to be more efficient as the carbon price signal is passed through on transportation fuels, electricity, and natural gas. Agriculture can participate through projects that generate offset credits. The fossil fuel portions of biofuels and bioenergy are under the cap and have a compliance obligation. However, biomass-derived fuels are exempt from a compliance obligation since CO_2 emissions resulting from the combustion of biomass are considered biogenic.

Separately, facilities must report biofuel data as part of the mandatory reporting regulation.

B-38. Comment: The SO2 allowance program under the federal Clean Air Act was originally set above the then current emission level from regulated sources, in order to allow the regulated units to adjust to the cap and plan strategies for compliance after the cap declined. The result was that the allowance prices remained reasonable and the market was somewhat predictable and efficient. And the program worked. ARB should follow the federal example and set the cap at a level that does not immediately induce shortages in the first year of the program. (HOR)

Response: We considered all examples from other market-based systems when determining how to set the cap. The cap provides for a modest decline on the order of 2 percent from forecast emissions in 2013, the first year with a compliance obligation in the regulation. Then the cap declines at approximately 3 percent for subsequent years. The cap is based on the best available information that included reported facility-specific information collected as part of the mandatory reporting regulation and improved statewide GHG emissions forecasts.

B-39. (multiple comments)
Comment: California has suffered a significant economic downturn that has resulted in a significant decline in fuel use. The current baseline (which may be close to 165 MMT per year) cannot be used as a reliable predictor of CO_2e emissions in 2012. It is very likely that this cap will end up being well below the normal "business as usual" emissions of CO_2e. (HOR)

Comment: The proposed "cap" begins in 2012 at 165.8 $MMTCO_2e$, the amount ARB estimates will be business as usual for the covered entities. Absolutely no reductions will be required that year. The cap fails to meet the requirements of AB 32 to achieve the maximum technologically feasible reductions. (CRPE1)

Response: We adjusted our estimates to take into account for the economic downturn and the changes in fuel use are reflected in the baseline. The initial 2012 allowance budget of 165 MMT per year was selected based on projected 2012 emission levels and using mandatory reporting data to ensure accuracy in cap setting. Covered entities will be required to reduce emissions starting in 2013, when the compliance obligation begins. AB 32 requires ARB to balance many objectives, including achievement of the maximum technologically feasible and cost-effective GHG reductions.

B-40. (multiple comments)
Comment: The proposed caps are not set in line with the full potential for cost effective abatement within the State and also includes generous offsetting provisions from the outset which will significantly weaken investment signals in capped sectors. The clarity of targets for the period 2012-20 is good. However, the fact that there is no continuation

beyond 2020, and no sign of Federal legislation to replace it, is a serious weakness and one that needs to be addressed as soon as possible. (SANDBAGCC)

Comment: The most serious concern relating to the current proposals relates to the lack of a cap post 2020. With some sectors only entering the system in 2015 they are being given only a 5 year timeline of required reductions. This is not a long enough payback period to justify investment in emissions abatement and will likely mean that participants view the regulation as a requirement to offset and little else. There will certainly be little incentive to over comply and bank since the value of banked credits will likely fall to zero in the event of the regulation stopping in 2020. We recommend that at the earliest possible opportunity new regulations are agreed that create targets beyond 2020, either in the form of 2050 targets or as a continuing annual reduction rate with no sunset clause. (SANDBAGCC)

Comment: We are glad to see that ARB is proposing a very clear, specific annual allowance budget for nine years, through 2020. It would be better if this was even longer. We encourage ARB to at least commit to publishing a fixed budget on a rolling basis. For example, publishing an updated nine-year budget, on a rolling basis, after the conclusion of each three-year compliance period. While there is no "magic" length of time that is clearly ideal, it is our sense that a longer period than nine years would better serve the market. Regardless of how far into the future the budget is published, ARB should be clear about how it will go about adding additional years to the back end of the schedule on an ongoing basis, and we encourage ARB to provide those periodic extensions earlier rather than later. The longer the 2021 allowance budget remains a mystery, the more "noise" is injected into the market, and the less comfortable market participants become with the price signal the market provides. (MSCG2)

> **Response:** Annual allowance budgets are described in the regulation. We considered all stakeholder comments when determining the length and duration of allowance budgets. The cap-and-trade regulation will use a nine-year cap that is divided into annual budgets, each of which specifies the number of allowances created for each year. We will evaluate the need to extend the allowance budgets to future years during periodic reviews of the regulation. We believe that we are meeting the legal mandates of AB 32 to reduce GHG emissions to 1990 levels by 2020. We recognize the importance of the 2006 Executive Order S-3-05 that orders an 80 percent reduction below 1990 levels by 2050. We will continue to implement both directives. We believe that the cap-and-trade program will provide a cost signal to covered entities so that they can make choices to investment in clean energy technologies to comply with the regulation.

B-41. (multiple comments)
Comment: CARB has dramatically reduced the 2020 allowance budget for the cap-and-trade program, which will increase the economic burden on California's electric customers. CARB has lowered the 2020 allowance budget to 334 million metric tons MMT CO_2e (from 365 MMT CO_2e in its 2008 Scoping Plan), but has not changed its overall 2020 carbon goal from 427 MMT CO_2e (1990 emissions levels, consistent with

AB 32). SCE requests clarification as to why CARB's adjustment in its allowance budget appears to shift the burden of carbon reduction more heavily to capped sectors. (SCE1)

Comment: CARB's adjustment of the 2020 Cap and Trade target from Scoping Plan levels using mandatory reporting data is flawed and inconsistent with AB 32.
As CARB has acknowledged, the 2008 Scoping Plan's estimate of the target for the 2020 allowance budget was 365 MMT CO_2e. The proposed regulation reduces the 2020 allowance budget from 365 MMT CO_2e to 334 MMT CO_2e, but lacks a clear discussion of the new numbers behind this adjustment. In the absence of this data, SCE requests clarification on CARB's methodology and updated emissions estimates. SCE is particularly concerned that the burden for emissions reduction will fall much more heavily on capped sectors, while the burden for reduction on uncapped sectors has correspondingly contracted. CARB provides a short explanation of this adjustment in Appendix E of the proposed regulation, and states that due to improved emissions estimates, they have revised the 2008 broad scope emissions number from 440 MMT CO_2e to 403 MMT CO_2e, a decrease of 8.5 percent. Accordingly, CARB staff decreased the cap by 8.5 percent, from 365 MMT CO_2e to 334 MMT CO_2e. This revision in the 2020 cap number lacks satisfactory reasoning, and supporting data and details are not present in the proposed regulation. SCE requests that CARB clarify its adjustment in emissions reductions by providing stakeholders with the following detailed information and allow for stakeholder input concerning the implementation of any changes to the 2008 Scoping Plan's reductions requirements.

1. A full breakdown of the initial, unadjusted estimates used in the Scoping Plan to define the emissions reductions required to meet AB 32 targets by 2020. These data points include but are not limited to:
   a. 2012 emissions levels;
   b. Total 2020 BAU emissions levels and 2020 emissions levels under AB 32;
   c. A breakdown of the 2020 BAU emissions levels and 2020 emissions levels under AB 32 between the capped and uncapped sectors; and
   d. Emissions reductions (from 2012 to 2020) required by each measure under AB 32.
2. The adjusted numbers corresponding with each initial data point listed above.
3. CARB's methodology and reasoning relating to this adjustment. (SCE1)

Comment: The proposed regulation is based on a new, poorly documented 31 MMT increase in the stringency of the cap and trade program that primarily impacts EITE entities. Since back-up data was not provided to change the programmatic cap that was adopted in the Scoping Plan, the allowance budget should not be revised as proposed in the proposed regulation. The Scoping Plan provided a preliminary estimate of 365 MMT. The cap-and-trade proposed regulation proposes a substantially lower allowance budget of 334.2 MMT. This equates to an additional 31 MMT reduction. The method to establish the preliminary estimate of 365 MMT was clearly described in the December 2008 Scoping Plan. In the cap-and-trade proposed final regulation, Staff used emissions data for calendar year 2008 to adjust the proposed allowance budget for 2020 (see Appendix E, page E-8). In the Scoping Plan, projected emissions from sources outside in the cap-and-trade program were 57 MMT in 2020. In the final draft regulation, the 57 MMT has increased to 85 MMT. This adjustment reduces the allowance budget in 2020, which impacts the allowance budgets for the entire program. We recommend that ARB restore the allowance budget to the documented level shown in the Scoping Plan of 365 million metric tons. This would require a change in the allowance budget for the year 2020 in section 95840. (DOWCHEM1)

Comment: CCEEB is concerned that the cap in this regulation exceeds previously defined scoping plan levels, driving the program reductions below 1990 emissions levels. CCEEB recommends that ARB clearly articulate the rational for this increased compliance obligation and the reasons why the emission estimates are higher when the economy, production, and business are down, and reconcile this data with the updated GHG forecast. (CCEEB1)

Comment: The proposed regulation includes specific allowance budgets for each year that are in error due to inappropriate adjustment to the Scoping Plan 2020 GHG target. The Scoping Plan clearly sets the 2020 target for AB 32 at 1990 emission levels, and sets the target for the sectors covered by the Cap and Trade program at 365 MMT. However, the budget for 2020 in Table 6-1 of the Proposed Regulation is 334.2 MMT CO_2e. The proposed regulation can change the 2020 target to the extent the scope of sectors participating in the Cap and Trade program is changed. Staff provided information in discussions that the exclusions were for non-covered emissions in capped sectors. Staff calculated a new broad scope 2020 allowance budget of 334 $MMTCO_2e$ by multiplying the Scoping Plan 365 $MMTCO_2e$ 2020 budget estimate by the ratio of the improved estimate of 2008 broad scope emissions (403 $MMTCO_2e$) to the 2008 emissions inventory estimate for broad-scope sector categories (440 $MMTCO_2e$). However, in the Scoping Plan, the Recycling and Waste sector was omitted from the industrial sector. Assuming that landfill gas and wastewater treatment were already deducted in the Scoping Plan, the method used by ARB to reduce covered sector emissions double counts the Recycling and Waste sector emissions. The 11.7 MMT in this sector should be excluded before creating the ratio since they were excluded in the Scoping Plan. This means that 403 would be divided by 429.3 and multiplied by 365 totaling 342.6 MMT. (SEMPRA1)

Comment: The proposed rule and ISOR fail to provide details on the calculations used in arriving at key elements of the rule, including the Annual Budget Amounts, the cumulative offset use limit, and the calculation of amounts placed into the reserve. It is particularly important to provide a clear description of the calculation resulting in the 8.5 percent reduction in the 2020 allowance cap from 365 MMT identified in the Scoping Plan to 334.2 MMT identified in the rule. (ANALYSISGRP)

Comment: The AB 32 goal of reducing statewide emissions to 1990 levels by 2020 establishes a hard target for the economy-wide emissions level (427 MMT CO_2e). ARB's Scoping Plan initially estimated the 2020 cap for sources covered by the Cap and Trade program at 365 MMT CO_2e. The proposed regulation revises the 2020 cap level for sources covered by the program to 334.2 MMT CO_2e. This presumably means that the expected emissions from sectors and sources outside of the cap and trade program have increased, as the overall economy-wide emissions level in 2020 should remain constant at 427 MMT CO_2e. However, ARB has indicated that the revised estimate is based on better facility level data for emissions from sources covered by the Cap and Trade program. DRA requests that the difference in cap calculations should be further explained in Appendix E: Setting the Program Emissions Cap, as the credibility of the 2020 cap calculation is critical to the cap and trade program. It is important that both capped and uncapped sources share the responsibility of emissions reductions in California. (DRA)

Comment: Staff is proposing to lower the original cap by 34 MMTCO_2e because of the recession and the updated emission inventory. The advancement of the reductions does not allow a transition period into the program. We believe that this will lock in a recession and prevent growth and recovery by the affected entities. The cap level should stay at the original level and be lowered as needed to reach the goals of AB 32 by 2020. (AGCOALITION)

Comment: The Utilities would like clarification regarding the revised 2020 allowance budget as presented in section 95841 (Table 6-1). The AB 32 Scoping Plan included a preliminary allowance budget estimate of 365 MMT in 2020. However, the proposed regulation includes a substantially lower allowance budget of 334.2 MMT in 2020. The Scoping Plan clearly articulated that the primary goal of AB 32 is to reduce GHG emissions to 1990 levels, which CARB established in its 2004 GHG inventory as being 427 MMT. Subtracting 57 MMT of emissions from sectors outside of the cap, plus a safety margin of 5 MMT, creates the annual allowance budget cap of approximately 365 MMT. In order to justify this change in the 2020 allowance budget, the emissions outside of the cap would have to increase from 57 MMT to 85 MMT (427 MMT – 334 MMT). The Utilities would like more justification from CARB as to why the emissions outside of the cap are expected to increase by so much more than originally projected and request that this analysis explain the differences between the original and updated forecasts. (MID1)

Comment: PG&E requests further clarification and examination of the Cap and Trade program's allowance budget for the year 2020 as established in section 95840. The Scoping Plan included a preliminary estimate of 365 MMT. The Cap and Trade regulation proposes a substantially lower allowance budget of 334.2 MMT. Given the importance of the year 2020 allowance budget to the Cap and Trade program, it must be a credible and well-supported number. PG&E appreciates staff's assistance in providing background information on staff's projections of year 2020 emissions from sources outside the Cap and Trade program, but would like to better understand why the forecast has increased by such a large amount. PG&E therefore requests additional information related to ARB staff's revised forecasts of emissions outside the Cap and Trade program. (PGE1)

Response: The Scoping Plan included a preliminary estimate of the cap-and-trade program 2020 allowance budget. In the cap-and-trade regulation, we incorporated an improved approach of estimating the allowance budgets and estimate budgets for all years from 2012-2020. Because of allowance banking, the program stringency is best evaluated by considering all years.

The starting allowance budget was initially set to equal the expected emissions for the year that a covered entity enters the cap-and-trade program. With this approach, the allowance budgets enable emissions to continue as expected under business-as-usual (BAU) conditions in the first year of a sector's inclusion in the program. The initial budget for 2012 was selected based on the projected 2012 emission levels. This BAU estimate reflects the current economic downturn and incorporates reductions achieved by 2012 from other Scoping Plan measures. Although 2012 is no longer a compliance year, the allowance budgets developed using this starting point remain unchanged. After accounting for expected offset use, the initial budget level provides flexibility for capped sources to increase emissions if necessary in the first few years of the program, beyond emission levels that are currently projected (see Figure E-3 in Appendix E of the Staff Report).

Many commenters focused on our methodology for calculating the cap-and-trade 2020 target and the difference from Scoping Plan preliminary 2020 cap levels. We calculate the economy-wide 2020 target required by AB 32 to be 427 MMT. The estimated cap in the Scoping Plan was 365 $MMTCO_2e$, and in the regulation the value is 334 $MMTCO_2e$. The primary drivers for this difference are: (1) the cap in the Scoping Plan estimate was based on entire sectors, rather than just capped emissions in each sector; (2) the Scoping Plan cap did not consider estimated offset use from in-state projects in 2020; (3) the Scoping Plan cap did not consider use of banked allowances in 2020; and (4) the Scoping Plan estimate did not consider some sources that are not counted by the regulation or certain types of transportation fuels that are used in small quantities.

As stated above, the 2020 level in the Scoping Plan did not consider the potential use of offset projects from in-state sources and banked allowances from prior year budgets. Offset credit use from in-state projects would result in additional emissions from capped sectors allowable due to reductions from non-capped sectors. Banked allowances could also allow for greater emissions from capped sources beyond the 2020 allowance budget. The Updated Economic Analysis of the Climate Change Scoping Plan completed in March 2010 carefully considered banking, and indicated that a drawdown of bank levels would likely be occurring in 2020 under most likely scenarios. The adjustment to the budget for 2020 was made after considering these factors and the 2008 facility-level data that was gathered through the mandatory reporting program that improved emissions estimates for the covered entities. Using these improved estimates, we calculated a broad-scope 2020 allowance budget of 334 $MMTCO_2e$.

B-42. (multiple comments)
Comment: Benchmarks must be reduced even further, while the dates for these caps to be made even earlier. Secondly, I believe the earlier we make the dates for meeting benchmarks of emissions and the earlier we start creating jobs with that goal in mind the better. We are currently in a global economic depression, and only by taking immediate action do we give the citizens of our country and of our world the ability to rise up out of this recession. Therefore, the caps and dates in the regulation should be reduced and brought closer to present time, respectively. (JACOBSONFRIED)

Comment: A more realistic time frame would either involve a later period for reducing the cap, or would involve a less restrictive cap in the early years. (HOR)

> **Response:** We disagree with any adjustments to the start and end dates. We will initiate all elements of the program throughout 2012. However, the first year of compliance for covered entities starts in 2013, to ensure that all central elements of the program are fully developed and tested. This provides the market with certainty about the program's direction. The cap declines at a steady level from 2013 to 2020 in order to meet the 2020 emissions goal.

B-43. (multiple comments)
Comment: We have significant concerns regarding the slope of the cap particularly in the first and second compliance periods. The first compliance period may be significantly impacted by the potential lack of supply of offsets and because it is unlikely that California's program will be broadly linked with other state, federal or international programs in the early years. Our concern is that the combined effects of the steeper cap slope and the tightening of the allowance due to reserve deductions and the increased auction and the potential entry of transportation fuels all in the second compliance period are likely to result in serious impacts to the economy. Chevron recommends that the cap slope be revised to reflect a smoother transition of 1 percent in 2013 and 2014, and 2 percent per year in the second compliance period. Even with these recommended changes, the AB 32 cap is still likely to be equally or more stringent than duplicative, command and control regulations under the Federal CAA scheduled to come into effect in 2011. ARB should consider proposing that reductions under AB 32 will constitute conformance with the CAA. (CHEVRON1)

Comment: The rate of reduction of the cap (cap slope) is too aggressive. The aggressive rate of reduction in the first compliance period is a particular concern because ARB does not expect to have linkage with other larger GHG cap and trade programs, and due to the limited protocols and administrative burdens, there will likely be a limited supply of offsets. These factors, coupled with the aggressive rate of reduction in the early years, place unreasonable pressure on sources that are struggling to identify and implement the best and most efficient methods to reduce GHG emissions. The aggressive cap slope, steep rise of allowance reserve deductions from the allowance pool, increased compliance obligations caused by ARB's finding of refining as a medium trade exposed sector, and the potential for placing transportation fuels under the cap (all scheduled to occur in the second compliance period), are likely to combine and cause adverse impacts to the economy in 2015. WSPA recommends that ARB significantly ease the required reductions in the first compliance period, decrease to 2 percent of the required reductions in the second compliance period and back-load more of the required emission reductions into the third compliance period. Back-loading will facilitate an orderly transition that may help achieve the emission reductions required under AB 32 and allow facilities time to implement their particular emission reduction strategies, and prevent significant economic impacts until California can realistically link its program to other GHG markets. Such linkage will allow California to achieve cost effective reductions without significant economic impacts. (WSPA1, WSPA2)

Comment: CCEEB recommends that the cap slope be revised to reflect a smoother transition of 1 percent in 2013 and 2014, and 2 percent per year in the second compliance period. This creates a smooth transition and realistically addresses the potential that California's cap and trade program will operate without the possibility of broad linkage to other State or federal programs in the first five years. (CCEEB1, CCEEB2)

> **Response:** We believe the cap trajectory and slope provides a gradual GHG emission reduction path toward the 2020 target. This is appropriate because the starting allowance budget levels are equal to expected GHG emissions for the year that a category of covered sources enters the cap-and-trade program. The allowance budget levels increase in 2015 as fuel suppliers are phased into the program to cover GHG emissions from distributed fuel use. We have also evaluated offset supply and believe that offset supply is unlikely to be a concern during the first compliance period. We will consider linkage with other jurisdictions as soon as practicable, as early as mid-2012.

B-44. Comment: The accuracy of the cap is significant in a modified “market based” regulatory system. Scarcity drives up prices of CO_2e, and therefore drives up prices of the underlying goods or services. A small scarcity generates significant market disruption and price spikes. A large scarcity results in massive economic disruption that will make the program unsustainable. The inability to know in advance whether the cap will be too high or too low means that individual market participants have no way of knowing how to bid for or price compliance instruments. It is therefore essential to set the cap at the “correct” level to achieve the purposes of the proposed rule.
Ensure that the cap is set for a period of at least five years at a level that exceeds existing emissions levels. This will allow for an orderly transition to a lower-cap environment, constrain growth in GHG emissions, and avoid unproductive price spikes or reductions in economic activity. (HOR)

> **Response:** Setting the cap above existing emission levels for five years would require having to decline the cap at a very rapid rate to meet the 2020 goal. However, we believe the regulation includes cost-containment mechanisms that protect against market disruption and price spikes. We established an allowance reserve account, which allows covered entities access to allowances at set prices

as a hedge against higher costs and helps reduce compliance costs without compromising the environmental goals of the cap-and-trade program.

B-45. Comment: Carbon allowances should be like voting. We have one person one vote. Why not one person one carbon allowance? A person should be able to benefit from selling his carbon allowances to, say, Chevron. There would be much less administrative overhead to tax carbon as it comes out of the ground or into California. (KRINOCK)

Response: We do not agree with the commenter's suggestion that each person should directly receive allowances. It would not be administratively efficient to allocate allowances to all residents of the State and ask them to participate in allowance trading. However, we recognize the public asset nature of the atmospheric carbon sink; in making decisions on allowance allocation we did consider the notion that the atmosphere is a global commons to which all individuals have equal claims.

We have performed an analysis of alternatives to the cap-and-trade program, including a carbon tax, and have found that none were as, or more, effective than a cap-and-trade program in carrying out the goals of AB 32. More information can be found in the Alternatives Analysis of the Staff Report. We also considered alternative points of regulation for the cap-and-trade program, including a fully "upstream" system where the obligation is assessed where fossil fuels are extracted or imported into California. We chose not to pursue this upstream approach due to administrative concerns including harmonizing with the existing framework for reporting of greenhouse gases which is primarily source-based.

Support the Cap

B-46. (multiple comments)
Comment: We are pleased to see that the proposed regulation contains several elements that I believe will make the program effective. These include a declining cap that starts at a level less than 2008 emissions and declines 2-3 percent per year to reach 1990 levels by 2020. (LUDLOW, UCS1, WALTERS)

Comment: Parts of the proposal are strong, such as setting a limit that declines each year, and setting a minimum price on carbon pollution. This steady price signal will help businesses make long-term investments in strategies to reduce global warming emissions. (MSCG2, FORMLETTER06)

Comment: We support the cap established in the regulation to reduce emissions by at least 18 $MMTCO_2e$ and potentially as much as 27 $MMTCO_2e$. This is consistent with the goals outlined in the Scoping Plan. (NC1)

Comment: TNC supports the overall declining cap. (NC2)

Comment: I support the declining cap. (CPC2)

Response: Thank you for your support.

Allocation Plan

B-47. Comment: ARB should revise the proposed rule to provide ample notice of the rules for allocation, rebate and other unfinished topics, each of which would take effect in 2015 or in later compliance periods. The key to efficient planning is clear advance notice of the rules and any changes. In order to make investments in the first few years of the program (instead of leaving California), businesses will need some confidence that the program will remain in place in a form that results in predictable costs and benefits. (HOR)

Response: We modified Subarticle 9 "Direct Allocation of California GHG Allowances" to address the commenter's concerns.

Opt-in Entities

B-48. (multiple comments)
Comment: The Proposed Regulation sets the 2020 allowance budget at 334.2 $MMTCO_2e$. This is a 30.8 $MMTCO_2e$ reduction from what was originally included in the Scoping Plan. CARB notes that the allowance budget has been adjusted downward from the estimated 2020 cap of 365 $MMTCO_2e$ that was set forth in the October 2008 Scoping Plan, due to the fact that reported data has allowed CARB to better estimate which sources within a capped sector will actually be part of the program. If the allowance budget has been reduced to reflect entities within "covered sectors" that are not actually "covered entities" within the scope of the program, then the allowance budget should be revised upward anytime one of those other entities is brought within the program by electing to be an opt-in covered entity. Accordingly, NCPA recommends that the allowance budget be revised upward to reflect this potential, or that the provisions of section 95813(e) be revised to allow an increase in the budget consistent with the increased demand for allowances consistent with the inclusion of each opt-in covered entity. (NCPA1)

Comment: Entities that are allowed to voluntarily enter the Cap and Trade program need to have their emissions added to the available allowance pool. Hundreds of thousands of allowances could potentially be taken out of the supply for regulated entities if their GHG emissions are not added to the cap. (AGCOALITION)

Comment: Section 95813(e) states that "Opt-in participation shall not affect the allowance budgets set forth in subarticle 6." To SMUD, this seems technically incorrect. An opt-in entity is bringing emissions under the cap and trade structure, and removing them from the category of remaining emissions that fall under the required AB 32 cap. If opt-in entities do not affect the budgets set forth in subarticle 6, the result will be that total emissions will be below the AB 32 cap, and that prices in the cap and trade market will be higher than necessary. SMUD recommends striking section 95813(e). (SMUD1)

Comment: If non-covered facilities "opt-in" to the cap-and-trade program, they are likely to do so because they can easily reduce energy use and seek to make a profit selling excess allowances. CARB needs to ensure that its provisions for allowing facilities to opt in address the potential that the facilities could increase the number of available allowances, dampening the incentive for covered facilities to reduce emissions. Just as the cap will be adjusted when transportation fuels are added to the program in 2015, the cap may need to be adjusted to account for the emissions associated with facilities that opt in. (USFLAW)

Comment: The allowance budgets set forth in Article 6 for the first compliance period should change as entities opt-in. The allowance budget is set for 2012 based on the expected GHG emissions of covered entities in 2012, with reductions in subsequent years. If the universe of covered entities changes, the allowance budgets should change accordingly. No change is necessary for 2015-2020 budgets since these opt-in customers would otherwise be part of the GHG emissions covered by the fuel providers. Modify section 95813(e) as follows:

> ~~(e) Opt-in participation shall not affect the allowance budgets set forth in subarticle 6.~~ (SEMPRA1, MID1)
>
> **Response:** As mentioned in the Staff Report, the purpose of including opt-in covered entities is to incentivize entities to implement more efficient processes and technologies to reduce their GHG emissions, so they can receive a higher number of direct allocations of allowances based on the product output-based benchmarking technologies. Because an opt-in participant's annual emissions must be below 25,000 $MTCO_2e$, only a few opt-in covered entities may participate in our program. The total GHG emissions from these potential opt-in covered entities are negligible.

Third-Party Participants

B-49. Comment: We have a concern about third-party market participants and possible market manipulation. WIRA is concerned about the ability of a non-obligated party's ability to participate in California's carbon market. Speculators in the oil and gas markets have historically affected price and reduced the efficiency of the open market. WIRA recommends CARB limit the eligibility or limit the participation, of non-obligated parties so that such influence on the carbon market can be minimized. (WIRA1)

> **Response:** We disagree with the commenter's suggestion that we should limit the eligibility and participation of third-party market participants in the carbon trading market. Third-party market participants will ensure a more liquid market. As discussed in Chapter II of the Staff Report, we designed the regulation to prevent market manipulation. For example, we included information with strong market oversight and disclosures in the rules to assist in monitoring the market.

We also included provisions prohibiting trading activities involving fraud, reporting false or misleading information, misrepresentations, and manipulations that are commonly used in other markets. We also included provisions to prevent entities from "cornering" the market. Finally, as stated in Resolution 10-42, we will contract with an independent entity with appropriate expertise that will monitor and provide public reports on the operation of the market, including auctions and reserve sales, on a quarterly basis, and recommend appropriate action. Such action could include taking corrective action prior to the next auction, adding future allowances to the allowance reserve or future auctions, or temporarily suspending trading in the market.

Compliance Plan

B-50. Comment: The Board should direct staff to prepare a plan that specifies the tools and guidance that covered entities will need to comply with the regulations, including such components as the allowance tracking system, the registration process, the leakage assistance allocation, the auction process and the process by which the Executive Officer shall determine emissions in the event positive or qualified positive verification is not attainable, among other components. The Board should direct staff to prepare a plan that specifies the compliance activities affected by these tools and guidance. The Board should direct staff to prepare a plan that specifies the timeline, milestones and deadlines for staff development of these tools and guidance. The resolution should further provide that the identified aspects of the AB 32 program shall not commence unless the necessary tools and guidance are available to covered entities no less than six months prior to the date on which covered entities will need such information to commence operation under the cap and trade program. (CCC, MAZOWITA)

Response: Staff reported to the Board on the status of implementation activities at the August 24 Board meeting, including a schedule for development of a market trading system and training for market participants. We will provide tools and guidance to help covered entities understand and comply with the regulation. We do not anticipate developing a compliance plan. However, we will consider using tools, such as a guidance document for implementation, to help covered entities comply with a regulation.

We will monitor whether the cap-and-trade program is meeting the objectives set forth in AB 32. Much of the monitoring information collected as a part of normal program management includes: emissions data reports from the mandatory reporting regulation; allowance price and use from the market tracking system; and offset project annual reports from the compliance offset program. Additionally, we will emphasize monitoring for potential emissions increases and economic leakage during implementation.

Using the results of monitoring, we will regularly evaluate (at a minimum once every three-year compliance period) whether the objectives identified by AB 32 are being achieved. We will conduct the evaluation sufficiently in advance of the end of each compliance period to allow for sufficient time to adjust the cap-and-trade program, if warranted, before commencement of the next compliance period. If we determine during the periodic review that the cap-and-trade program is not achieving the objectives as defined by AB 32, or if substantial, unanticipated adverse economic or environmental effects are identified (e.g., substantial leakage), we will revise the operation and/or design of the program accordingly.

Sectors/Facilities/Alternative Fuels

Cross-Sector Equity

B-51. (multiple comments)
Comment: Regulations should avoid picking “winners and losers” and instead focus on treating all sources equitably, so that the market and public can decide the most cost-effective outcome. ARB should review the regulation to ensure that it is fairly structured and can be applied equitably; remove situations where subsidies can occur or where allowances or allocations are not apportioned equitably; and ensure that fees or assessments are fairly applied. (WSPA1, WSPA2)

Comment: A cap and trade system that distinguishes emissions from different sectors for differential treatment does not result in market consistency, or equitably distribute economic burden and opportunity, and is a serious violation of the intent of a cap and trade program. This is the case when it comes to the regulation’s treatment of the electricity sector. The most egregious example is the use of auction revenue to mitigate the price impact of carbon costs in this sector, and in this sector only. (BP)

Response: We considered cross-sector equity issues when developing the regulation. We believe that the costs of the cap-and-trade program are equitably distributed through the overall approach. The regulation relies heavily on free allocation in the program’s early years. In the regulation, we used emissions intensity as a measure of the impact that carbon pricing will have relative to a sector’s economic output. Sources with higher emissions per unit of output are considered to be more emissions intensive. We also looked at trade exposure as a measure of a sector’s ability to pass through a cost. The number of allowances allocated to an individual facility is based on an emissions efficiency benchmarking approach.

In industrial sectors that are impacted by carbon allowance cost and cannot pass through those costs to customers without suffering a competitive disadvantage, free allowances are distributed. The approach is somewhat different for the electricity sector, which generally can pass costs through to end-users of electricity. However, the electricity sector is also subject to many additional costs, such as that of the Renewable Portfolio Standard. The regulation does not regulate the use of auction revenue.

Glass

B-52. Comment: Given the number of unresolved issues related to setting an EEB in the container glass sector, CARB staff should continue to work with sector representatives to finalize an appropriate sector EEB by June 2011. (SMITHS)

> **Response:** We will continue to work with the container glass industry to establish the output-based benchmark (noted in this comment as the EEB). The final regulation includes a benchmark for container glass. The commenter recommends establishing an EEB for the container glass manufacturing sector employing nationwide data, not California-only data. We disagree that the benchmark should be based on data that is not representative of what occurs in California. Over-estimating the benchmark for facilities in California could lead to an over-allocation of allowances to any given industry. Furthermore, the validity of much of the California data can be verified due to reporting required for the MRR; this is not the case for national data.
>
> We do not think it is necessary to expand the process for establishing an EEB to depend on electrical consumption data, as no benchmarks include electrical consumption. We do agree that there is a need for adequate review of any sector-specific EEB-setting methodology proposed by CARB staff. It is important to note that much of the data used to determine benchmarks is confidential. However, as part of ongoing work with industry, staff provided data and discussed its use with a representative of the container glass industry that was approved for access to the confidential data. We have not received questions or comments from industry since that discussion.

Transportation Fuels

B-53. Comment: CTA requests that CARB remove diesel fuel outside the declining cap pursuant to statutory requirements which state in plain English the definition of cost-effectiveness inherent in the legislative intent of AB 32. Capping emissions from the combustion of fossil fuels for transportation purposes is in no way the lowest cost means of achieving the requirements of Health and Safety Code section 38501(h). Health and Safety Code section 38505(d) defines cost-effective or cost-effectiveness and transportation fuels under the cap basically violate this section by adopting the least cost-effective carbon strategy with the highest cost. Adopting diesel fuel under a declining cap in conjunction with a low carbon fuel standard violates the spirit and letter of the law passed by AB 32 and threatens thousands of transportation related jobs throughout the state. In addition, it encourages the use of less clean, out-of state fuels and increases statewide emissions. (CTA)

> **Response:** Including transportation fuels and fuel suppliers in the cap-and-trade program will help achieve the objective of reducing emissions by 2020, and help to drive the long-term transition to cleaner fuels well into the future. Additionally, including these fuels in the program provides a consistent price on GHG pollution

throughout the economy and ensures a level playing field across all fuels and consumers. We believe that there are important benefits from the inclusion of transportation fuels and fuels for residential, commercial, and small industrial users.

The commenter states that subjecting diesel to a declining cap in conjunction with the Low Carbon Fuel Standard (LCFS) violates the spirit and letter of AB 32 because they are not cost-effective ways to lower carbon emissions. The LCFS regulates fuel producers by requiring them to reduce the carbon intensity of their fuels 10 percent by 2020. This is accomplished by creating various "fuel pathways" for fuels based on their lifecycle emissions, accounting for feedstocks, production processes, transporting fuels, and other means. Thus, the LCFS works in conjunction with the cap-and-trade regulation to help meet the objectives of AB 32.

B-54. Comment: CARB's projected baseline emissions inventories do not appear to account for the expected shift from petroleum transportation fuels to biofuels in the future (see http://www.arb.ca.gov/cc/inventory/data/tables/2020_ghg_emissions_forecast_2010-10-28.pdf). While some of this increase may be accomplished with lower carbon biofuels, this shift would set back CARB's efforts to achieve 2020 GHG goals unless transportation biofuels are included in cap and trade or the overall level of the cap and trade is reduced to account for leakage due to expected increasing levels of transportation biofuels. We strongly recommend that emissions from all transportation liquid fuels be treated equally and fuel providers should be held accountable under the cap for the carbon emissions of all biofuels. (KUSTIN03)

Response: The cap-and-trade regulation will help transition California away from carbon-intensive fossil fuels to cleaner and more-efficient fuels. The fossil fuel portions of biofuels and bioenergy are under the cap. Transportation fuels and fuel suppliers will have a compliance obligation. However, biomass-derived fuels are exempt from a compliance obligation since CO_2 emissions resulting from the combustion of biomass are considered biogenic. Emissions from biomass-derived fuels must be reported and verified pursuant to the MRR. Source categories that are not listed under section 95852.2 (Emissions without a Compliance Obligation) or that have not received a qualified positive or positive verification statement must be reported as "other biomass CO_2." Other biomass emissions that cannot be verified pursuant to the MRR are not considered biomass-derived, and will hold a compliance obligation.

B-55. Comment: The regulation does not contain sufficient design information on the important issue of transportation fuels. More detail is needed. BP strongly urges CARB staff to consider use of a fee on transportation fuels linked to the price of carbon in the cap and trade system. (BP)

Response: ARB considered the use of a carbon fee, either alone or in concert with a cap-and-trade program, and determined that the proposed cap-and-trade program provides acceptable price certainty while assuring that emissions do not exceed the 2020 target. For further details, please see the Analysis of Alternatives to the Proposed Regulation in the Staff Report. Further, as noted in the Supplement to the Scoping Plan Functional Equivalent Document (pages 94-95) there are significant challenges to adopting a fee in California. (see http://www.arb.ca.gov/cc/scopingplan/document/final_supplement_to_sp_fed.pdf)

Further details on the incorporation of transportation fuels into the cap-and-trade program in the second compliance period will be released as part of future rulemakings for the cap-and-trade regulation, and will occur in the first compliance period.

B-56. Comment: Placing diesel fuel under a declining cap as part of the Cap and Trade Program in 2015 will cause warehousing in California irreparable harm. Leakage of cargo and the associated value added services that California warehouse and supply chain partners provide to other ports, specifically Seattle, Houston, Panama and Canada do not improve overall carbon emissions. CARB must not adopt such an economically devastating regulation on California warehouse businesses without understanding the industry and careful economic monitoring through annual reporting back to this board. IWLA requests CARB abandon placing transportation emission under a declining cap. If you must move ahead against our counsel, we ask for the following safeguards to be put in place so that CARB doesn't inadvertently cause significant damage to CA's economy and irreparable harm to California third party logistics providers. IWLA is seeking:

1. Annual reporting of diesel prices of California and other port facilities including Washington, Texas, British Columbia and Panama.
2. Working to ensure a robust offset program to achieve compliance obligations post 2015 and ensure linkage to other programs.
3. Waiting until 2018 to place diesel fuel under the cap and reopening the discussion prior to 2015 of placing fuels under the cap to ensure a reliable, adequate, affordable supply of fuels to the consumers.
4. Expand offset use from eight percent to 25 percent so that warehousing can engage in distributed energy solutions for dealing with climate change instead of expensive fuel mandates. (IWLA1, IWLA2)

Response: The cap-and-trade program calls for periodic reviews, during which ARB staff will analyze fuel prices in California and neighboring states to ensure that prices in the State are not significantly higher than other regional prices. If we determine that the cap-and-trade program is not achieving the objectives as defined by AB 32, or if substantial, unanticipated adverse economic or environmental effects are identified (e.g., substantial leakage), we will revise the operation and/or design of the program accordingly. There are also several cost-containment measures that are integrated into the program, including the use of offsets, three-year compliance periods, and the Allowance Price Containment Reserve.

The fossil-fuel portions of biofuels are under the cap and have a compliance obligation. However, biomass-derived fuels are exempt from a compliance obligation since CO_2 emissions resulting from the combustion of biomass are considered biogenic. Separately, facilities must report biofuel data as part of the mandatory reporting regulation.

We have chosen to allow the use of offsets—up to the specified limit of eight percent—for compliance in the proposed cap-and-trade program.

B-57. Comment: We strongly advocate that transportation fuels should be included in the program from the start, while emissions from trade exposed, heavy industries should be brought in at a later date. This would make defending the proposal against claims of competitiveness impacts easier and should also have made agreeing a more ambitious target easier. Additional costs in electricity and fossil fuel markets can be passed through since the demand cannot easily be met by imports from uncapped states/countries or, where it can, the requirement to comply with caps can also be applied to the imported commodity. (SANDBAGCC)

Response: We do not agree that transportation fuels should be included in the first phase of the program. The program will expand in 2015 to include fuel distributors to address emissions from combustion of transportation fuels and combustion of natural gas and propane at sources not covered in the first phase of the program.

Including transportation fuels in the program in 2015 provides a consistent price on GHG pollution throughout the economy and ensures a level playing field across all fuels and consumers. We believe that there are important benefits of including transportation fuels and fuels for residential, commercial, and small industrial users. We also believe that it is appropriate to initially bring these fuels into the program on a reporting-only basis for the first compliance period. This will provide time for ARB and transportation fuel deliverers to work through any issues in the reporting system before they have a compliance obligation in 2015.

B-58. Comment: ATA supports ARB's decision to maintain a phase-in approach for the incorporation of transportation fuels during the second compliance period in 2015 as opposed to requiring compliance for all sources beginning in 2012. As noted in ATA's comments on the PDR, the phase-in approach allows for the smoother implementation of a complex regulation, while also allowing additional time for harmonization with regulations in other jurisdictions, especially given the interstate nature of transportation fuel consumption and associated emissions. (ATAA)

Response: No response necessary.

B-59. Comment: ATA raised several key concerns regarding the draft regulation and appreciates that aspects of those concerns have been favorably addressed. First, ATA appreciates that the regulation more clearly excludes aircraft fuel from coverage under the regulation and no longer includes a placeholder for the inclusion of additional fuels in the future. Consistent with ATA's earlier comments, the exclusion of aircraft fuel is necessary and appropriate in light of federal preemption of State regulation in this area. (ATAA)

Response: No response necessary.

B-60. Comment: The Cap and Trade program should not be extended to transportation consumer emissions as provisions of other federal and State programs address these. Additionally, fuel providers should not be responsible for these emissions that are directly consumer related. Transportation emissions should be considered only if a formal review determines that this action is necessary and implementation would be more cost-effective than other policy approaches. The proposed regulations include GHG emissions from consumer use of transportation fuels under the emissions cap starting in 2015 (section 95812(d)(1)). This results in a clear overlay to the existing federal Renewable Fuels Standard, the California Low Carbon Fuel Standard (LCFS), and State/federal vehicle GHG performance standards. Transportation GHG emissions are substantially addressed through current federal and State programs (i.e. federal fuel economy programs, federal renewables programs and State LCFS programs). Cap and Trade is not well-suited to address emissions from millions of distributed point sources such as automobiles. Inclusion of transportation fuel emissions within the Cap and Trade program will add a volatile carbon cost to the price consumers already pay for GHG control measures such as LCFS and vehicle efficiency standards. In addition, fuels under the cap will increase administrative complexity and the market price of emission allowances for all the other capped sectors. Specifically, a carbon cost of $20 per ton would add a fuel cost burden in excess of $3 billion per year to the California economy. In addition to individual consumers, much of this cost will fall on businesses and municipalities which will impact small business owners, truck drivers, city bus and trash services, construction companies, rail services, and others. This carbon cost, along with the cost of compliance for LCFS and federal programs, will be embedded into the costs of all goods and services that rely on transportation. CARB should not extend the Cap and Trade program to consumer emissions from use of transportation fuels. Instead, CARB should allow existing federal/State programs to address GHG emissions in this sector. (CONOCO)

Response: We believe that cap-and-trade's market-based approach is the most cost-effective and practical approach to lower emissions throughout most of California's economy. There are numerous sectors that are covered by direct regulation and the cap-and-trade regulation. For example, the electricity sector is subject to the Renewable Portfolio Standard as well as the cap-and-trade regulation. We believe that the cap-and-trade-program is complementary to existing renewable and LCFS standards and to other State or federal laws.

The LCFS regulates fuel producers by requiring them to reduce the carbon intensity of their fuels 10 percent by 2020. This is accomplished by creating various "fuel pathways" for fuels based on their lifecycle emissions, accounting for feedstocks, production processes, transporting fuels, and other factors. While the LCFS will incentivize the use of lower carbon, non-petroleum fuels, it does not address emissions from petroleum refineries. The cap-and-trade program addresses both facility emissions that occur from fuel production (beginning in the first compliance period) and accounts for combustion emissions from the fuel that is produced and sold in California (beginning in the second compliance period).

Placing a price signal on transportation fuels will reduce the consumption of transportation fuel; driving investment in newer, more fuel-efficient vehicles. Any GHG reductions resulting from federal regulations or the LCFS at covered entities would be counted as emission reductions under the cap-and-trade program.

We agree that cap-and-trade is not well-suited to address emissions from millions of distributed point sources such as automobiles. However, our approach is not to apply cap-and-trade to the end user (vehicle drivers), but to the fuel suppliers, who will be responsible for fuel that is combusted. By taking this "upstream" approach in the regulation, we avoid the challenges of applying it to millions of "downstream" users.

Agriculture/Food Processing

B-61. Comment: Many of the assumptions made throughout the document do not apply to agriculture or food processing. Therefore an industry-wide study should be conducted to fully understand the impacts to the food processing sector. We are hopeful that our analysis of the following assumptions will assist CARB staff when trying to determine appropriate participation for the agriculture and food processing sectors. (ACC3, CALFP1)

Response: We worked with, and received input from, the food processing and agriculture industry when developing the regulation. ARB is committed to continue to work with the agricultural and food processing industry to re-evaluate their leakage risk and associated allocation assistance factor and how the cap-and-trade regulation is affecting these sectors.

B-62. Comment: Assumptions on pay-back periods are faulty because CARB assumes pay-back periods on an annual basis. On page F-7, the regulation states that pay-back periods on capital costs are under three years. Many food processors operate only a few months out of the year, so this pay-back period on technology adaptation would have to be tripled or quadrupled to create a more accurate projection for our industry. (ACC3)

Response: We agree with your comment that facilities that operate only a few months out of the year will have a longer payback period than facilities that operate year round. The abatement cost curves use averages across industries to produce estimates on cost, cost savings, and GHG reductions. We made estimates to reflect lower utilization of some food processor facilities in the abatement cost curves by assuming a lower capacity factor for food processor boilers in the compliance pathways analysis. While these estimates may not be valid for all facilities in an industry, ARB staff believes them to be accurate for the industry as a whole.

Bioenergy/Waste-to-Energy

B-63. Comment: Under "Excluded Emissions" in CARB's proposal, a host of emissions would be subject to reporting thresholds, but would not be subject to a covered entity's compliance obligations. Several coal plants are contemplating the change to biomass fuel, which means biomass fuel will be at a premium and difficult to obtain, causing "green" electricity prices to go up and possible offline periods when biomass plants can't get fuel. (CONSTELLATIONENERGY)

Response: The updated economic evaluation of California's climate change scoping plan did not indicate that the use of biomass would increase in response to the proposed regulation. Increased use of biomass is already incentivized by existing regulations such as the renewables portfolio standards (RPS) and the low-carbon fuel standard. The RPS requires publicly owned utilities to obtain 33 percent of their energy from renewable resources, including biomass. Most utilities are challenged to achieve the renewable target despite the availability of biomass as a renewable fuel. Increased use of biomass for energy generation created by other state policies and initiatives, such as the Renewable Portfolio Standard, is discussed in the cap-and-trade FED (see pages 351-352).

B-64. Comment: Net emissions from all bio-energy, as determined by methodologies that CARB should develop, should be included under the cap and generate compliance obligations. (EDF1)

Response: The fossil fuel portions of biofuels are under the cap and have a compliance obligation. However, biomass-derived fuels are exempt from a compliance obligation since CO_2 emissions resulting from the combustion of biomass are considered biogenic. This is consistent with existing U.S. EPA framework. Separately, facilities must report biofuel data as part of the mandatory reporting regulation.

Research and Development

B-65. (multiple comments)
Comment: The proposed regulation does not adequately address the unique aspects of many company's operations, particularly in the Southern California area. Southern California represents substantial research and development operations. Predicting research and development activities several years in advance is problematic and impractical. (SDCHAMBER)

Comment: The proposed regulation does not adequately address the unique Research and Development aspects of Solar's San Diego operations. In comparison with typical manufacturing, predicting research and development activity several years in advance is problematic and impractical. (SOLARTURBINES1, SOLARTURBINES2)

Comment: The proposed regulation does not adequately address the unique aspects of research and development operations, particularly those that are closely tied to manufacturing and production facilities. It's also very difficult to predict research and development activities several years in advance. (INDENVASSOC)

> **Response:** We believe that the regulation adequately addresses research and development (R&D) operations, particularly those that are closely tied to manufacturing and production facilities. We've worked to understand greenhouse gas emissions from R&D with entities that conduct these operations. In one case we've developed an allocation benchmark specifically for turbine testing that covers research and development emissions. In the Staff Report, we note that auction revenue could potentially be used to create a low-carbon investment fund that would incorporate research, development, and demonstration of low-GHG industrial technologies.

Refineries

B-66. (multiple comments)
Comment: The industrial sector has zero tonnes of specific reduction requirements, including for the largest sources such as the oil industry. According to CARB, the entire Cap and Trade regulation will get an18 to 27 $MMTCO_2e$ reduction by 2020, but none of these reductions are required to be achieved by oil refineries. The regulation and Staff Report make it clear that no entity is required to reduce emissions at their site. AB 32 requires ARB to consider the significance of the contribution of each source or category of sources (in adopting a regulation). There is no way this can be argued as meeting AB 32's requirement to maximize reductions, and to reduce co-pollutants. CBE urges CARB to correct this egregious error. We suggest an alternative proposal. CARB should perform a thorough evaluation of Reasonably Available Control Measures necessary to meet CARB's requirements under AB 32 for maximum reductions, to reduce smog in non-attainment zones, and toxics in overburdened heavily industrial areas. Additional reductions could be achieved from the following:

- Requiring In-State reductions from industrial boilers and heaters, which CARB has already identified;

- Removing industrial exemptions for methane from smog regulations;
- Requiring implementation of specific refinery by refinery measures identified in the industrial energy efficiency audits;
- Limiting emissions and conversion to processing Heavier Crude at oil refineries (which is not cancelled out by adding polluting ethanol to gasoline); and
- Requiring oil refineries to switch fossil fuel electricity use to clean alternative energy sources (since oil refineries use significant electricity) (CBE1)

Comment: Cap and Trade industrial GHG reductions are tiny and can be beefed up. If instead achieved in-state, they would generate local jobs, health benefits, and be verifiable. (CBE1)

Comment: I am extremely disappointed with the proposed Cap and Trade approach you are considering. The proposed Cap and Trade approach has been tried in Europe and completely failed. You should vote to delay this proposed Cap and Trade approach and send it back to staff to develop a regulation-based approach that can guarantee achievement of AB 32 goals. (STEWARTJ)

Comment: The seemingly straightforward category of "oil refineries" is being parsed into bits, with oil refineries that process intermediate materials being exempted, and even removed from the definition of oil refineries in the regulation, despite the fact that they are inherently part of an oil refining company's overall production process. It's unclear whether the re-defined refinery portions are included in the capped emission estimation of 34 MM tonnes or not, but it is clear they are exempted from the caps. This approach undermines the requirement to adopt regulations that achieve technologically feasible GHG reductions from sources and categories of sources because it allows large unregulated oil refining emissions. The last sentence in the "Petroleum refinery" definition should be struck, as this definitional difference has no relation in determining whether such facilities emit large amounts of GHGs, criteria pollutants, or toxics. CARB should use standard industrial classification codes for oil refineries used by EPA and remove baseless exemptions, to prevent large unregulated oil refining emissions. For GHG purposes, there is similarly no justification for treating some refinery facilities as exempt without at least providing an emission threshold above which they are subject to regulation. Other entities must abide by simple emission thresholds (>25,000 metric tonnes), so this exemption also represents an unfair business practice, with oil refineries getting a sweetheart deal. (CBE1)

Comment: CARB originally considered direct control of oil refinery reduction measures and found them feasible, but later lumped oil refineries and industrial sources in with all other Cap and Trade sources, despite findings that direct controls were feasible. If CARB made these fixes for industrial sources and as well for other sources causing health impacts in California (such as agricultural and electrical sources), the severe impacts caused by Cap and Trade, and the ineffectiveness of it, would be greatly lessened. (CBE1)

Comment: The Staff Report expresses valid concerns about a program that applied facility-specific caps to all facilities. But the Staff Report evaluates only the most extreme version of this option. First, facility caps could be applied only to facilities in the State's most polluted areas. Second, the impact of facility caps would depend upon their stringency. The Staff Report rejects caps that would require each facility to reduce its proportional share of emissions. But a cap would not have to be that stringent. A cap that prevented the facility from increasing emissions would eliminate the risk of violating AB 32's requirement that the trading program prevent increases, while still providing substantial flexibility. If facility increases are as unlikely as the Staff Report claims, then such caps could ensure that the program complies with AB 32 without having a significant impact on covered facilities. To further AB 32 goals of complementing the State's efforts to achieve air quality, facility caps could, however, go farther than simply preventing increases. The caps could be set somewhat below the level of existing emissions. Such an approach could still be more flexible than the one that the staff rejected, because the level could be set somewhere between current emissions and the full proportionate share of reductions. The staff rejected facility caps because of their impact on cost-effectiveness. But a full assessment of cost-effectiveness should take into consideration not only the costs of pollution control, but the benefits of reducing pollution in heavily polluted areas. Thus, varying requirements depending upon the benefits of pollution control could be more, not less, cost-effective from the state's perspective. (USFLAW)

Comment: Impose individual facility caps for facilities in heavily-polluted areas. (USFLAW)

> **Response:** The commenters' concern is that GHG emission reductions should be achieved through direct regulation rather than a market-based, cap-and-trade compliance mechanism. Since these comments pertain to the overall GHG reduction strategy laid out in the AB 32 Scoping Plan, the comments are not applicable to the cap-and-trade rulemaking. However, we believe that inclusion of industrial sources in the cap-and-trade program provides a cost-effective method of achieving greenhouse gas reductions. The results of ARB's Industrial Energy Efficiency Audit Regulation will be used to evaluate the need for any future direct regulation.
>
> We disagree that we have created a "sweetheart deal" or inappropriately excluded any petroleum refining facilities than from coverage under cap and trade. The generic inclusion threshold (>25,000 metric tons CO_2e) applies to all refineries and related activities.

B-67. Comment: GHGs from oil refineries overall are getting worse due to switches to dirtier crude oil, running counter to other industries (such as electric power plants) that are switching to lighter feedstocks. A recent peer-reviewed study published by CBE Senior Scientist Greg Karras in the journal *Environmental Science and Technology* found that very large increases in GHG emissions are occurring due to the switching to dirtier crude oil at oil refineries, underlining the importance of accurate inventories and forecasts, and controls and limits addressing this switch. The new study provides a detailed evaluation of data nationally, which shows in detail how sharp this increase is. The paper found that "fuel combustion increments observed predict that a switch to heavy oil and tar sands could double or triple refinery emissions and add 1.6−3.7 gigatons of carbon dioxide to the atmosphere annually from fuel combustion to process the oil." We urge CARB to review the attached publication, and to address this issue. (CBE1)

> **Response:** The comment is outside the scope of the regulation. The choice of feedstock for an oil refiner is not prescribed by the regulation. If, however, the use of dirtier crude oil causes a refinery's GHG emissions to increase, then their compliance obligation will increase, and the increased cost of carbon will be incorporated into the final fuel cost. This provides an incentive to use the clean feedstocks.

Hydrogen Plants

B-68. Comment: Just one hydrogen plant can emit over a $MMTCO_2e$ per year (such as at the ConocoPhillips Rodeo facility), so it is almost certain that the total of 2.22 MMT listed for hydrogen plants now is actually much higher and getting even bigger than listed in the CARB chart. CBE has previously provided a partial list of additional hydrogen plant projects in comments to CARB, and we incorporate those by reference. CBE also previously requested that CARB perform a more detailed assessment of planned hydrogen plants expansions at refineries, and we included the following chart in both written comments submitted, and in testimony at a CARB hearing. Due to new hydrogen plants added, or in the process of being built, in the last decade, about 6 $MMTCO_2e$ emissions were added. This is a continuing trend that needs to be reined in. (CBE1)

> **Response:** We agree that hydrogen plants are significant sources of greenhouse gas emissions. Operators of new hydrogen plants will need to report their greenhouse gas emissions to ARB. The operators of these facilities will need to surrender compliance instruments to match against these emissions, so entities that are investing in such facilities will have to consider the cost of carbon when planning any new facilities. These emissions will be covered by the cap, but will not increase the total size of the cap, so any new emissions from hydrogen facilities will need to be counterbalanced by reductions elsewhere

B-69. Comment: Hydrogen Energy is in the process of a comprehensive regulatory review process to construct the nation's first industrial-scale low carbon power plant with carbon capture and sequestration. The proposed facility will use Integrated Gasification Combined Cycle (IGCC) technology to manufacture hydrogen from petroleum coke (a by-product of the refining process) or blends of petroleum coke and coal, as needed. Over two million tons of carbon dioxide (CO_2) is expected to be captured annually and used for EOR where it will result in sequestration in deep underground geological formations. In order to account for and recognize the benefits of a bold project like the

Hydrogen Energy project in California, and to send the policy signals that will lead to further investments in low-carbon power with CCS, CARB should specifically acknowledge the benefits of carbon capture and storage. The sooner CCS is available, the greater the cumulative benefit to the atmosphere. The need for early deployment of CCS is particularly pressing because of the long lead times in the power generation industry. Several years are required to design, permit and build a power plant, with Hydrogen Energy expected to be operational in California during the middle of this decade. (HECA)

> **Response:** We agree that carbon capture and sequestration (CCS) can play a critical role in reducing GHGs. However, these technologies are not currently commercially available. Inclusion in the regulation would be premature. We have been involved with CCS research studies and will continue to monitor developments in CSS and propose regulatory amendments to address it, as necessary.

Miscellaneous Facilities

B-70. Comment: All renewable energy performs significantly better than nuclear energy. Nuclear power also has serious adverse contamination effects on people and the environment for thousands of years for all phases from cradle to grave that far exceed dangers of all other energy sources. Nuclear power is not an acceptable contender in reducing global warming emissions. (MICHETTI)

> **Response:** The cap-and-trade regulation places a compliance obligation on certain entities that are responsible for GHG emissions. Nuclear power does not emit GHG emissions, and is not addressed by this regulation.

Cost-Effectiveness

B-71. Comment: ARB should closely monitor the Implementation of the Scoping Plan to ensure the State meets AB 32 emission reduction targets in a cost-effective manner. We recommend the following:

- The suite of programs ARB and its sister agencies are adopting under AB 32 are complex, and in the case of the electric sector in particular, rely on continuously evolving advanced technologies and challenging and unpredictable transmission and permitting conditions, among other uncertainties. For these reasons, PG&E believes that Scoping Plan updates are critical, and should be more frequent than the five-year cycle that the statute provides as a minimum. In particular, and as it relates to the Cap and Trade regulation, PG&E recommends that the relative cost-effectiveness of programs must remain a key consideration as California moves forward to achieve AB 32's goals;
- ARB should establish a clearer process for evaluating comparative cost effectiveness as an integral part of Scoping Plan review. Since AB 32 calls for maximizing cost-effectiveness, ARB should establish a clearer process to assess

each program measure to determine the cost per ton of CO_2-equivalent reductions;

- ARB should perform a comparative evaluation to determine the relative cost-effectiveness of each program measure vis-à-vis other programs and the Cap and Trade market;
- ARB should make adjustments to the program measures to maximize the extent to which regulated parties are able to pursue the most cost-effective measures, and to either improve the cost-effectiveness of the more costly programs, delay their compliance targets if cost trajectories are trending downward, or suspend programs entirely in favor of other program measures or the Cap and Trade market. This cross-measure comparison could also be used to expand programs that prove to be more cost-effective than others. PG&E proposes that these cross-measure assessments be performed at least every two years, and ARB would modify the programs as necessary in order to minimize higher program costs and to more accurately determine cost and emissions reduction trajectories. In the electric sector, existing reporting requirements should provide ample data to determine the reductions achieved by each of the program measures, while the Cap and Trade market provides a real-time allowance price by which to evaluate its comparative cost-effectiveness; and
- ARB should employ a comparative approach to cost-effectiveness evaluation, adjust program requirements as required to improve their cost-effectiveness and allow reductions to be achieved through switching to more cost-effective program measures or rely on more reductions through the Cap and Trade system when necessary. PG&E recommends that comparative cost-effectiveness analysis be a key component of Scoping Plan review, and that such review occur at least every two years rather than the statutory minimum of five years. Such review may, as noted, have the effect of greater reliance on reductions through Cap and Trade as AB 32 implementation through other programs evolves. (PGE1)

Response: The commenter's recommendations refer to the Scoping Plan and the need for a comparison of the cost-effectiveness of the various regulations developed in response to AB 32. The comments do not relate specifically to the current rulemaking on the cap-and-trade regulation. Nevertheless, as discussed in Chapter VIII of the Staff Report, the cap-and-trade regulation is designed to achieve the required emission reductions at the lowest cost to society. Specifically, the regulation is estimated to achieve the needed emission reductions at allowance prices in the range of $15 to $30 per metric ton in 2020. Should this estimate not prove to be accurate, the program has established price containment measures that would come into effect to mitigate excessively high prices.

B-72. Comment: The structure of the proposed Cap and Trade rule will place an overwhelming financial penalty on industry for relatively small "market-driven GHG emission reductions." This is because the Cap and Trade regulation focuses on "total carbon emissions" and not on reducing carbon emissions to meet the goals of AB 32. Even to the extent that GHG emissions are reduced to meet the 2020 goal, the ongoing financial burden of the existing carbon emissions will continue and have real-world impacts on our refining operations that are not adequately addressed. We anticipate the cost of this program to Valero and ultimately California businesses and consumers could approach $500 million by 2020 at the floor (minimum) price mandated by this regulation with little or no environmental benefit. (VALERO)

> **Response**: As discussed in Chapter VIII of the Staff Report, the cap-and-trade regulation is designed to achieve the emission reductions required by AB 32 in the most cost-effective manner. The regulation also establishes price containment measures that would come into effect to mitigate excessively high prices should they occur. Insufficient information was provided by the commenter on how their cost estimates were made in order for us to be able to respond to this comment.

B-73. Comment: ARB should closely monitor the Cap and Trade program, and the implementation of the Scoping Plan, to ensure the State meets AB 32 emission reduction targets in a cost-effective manner. (BCFSE)

> **Response:** As discussed in Chapter VIII of the Staff Report, the cap-and trade regulation is designed to achieve the required emission reductions in the most cost-effective manner. The regulation is estimated to achieve the needed emission reductions at allowance prices in the range of $15 to $30 per metric ton in 2020. Should these prices prove to be inaccurate, the program has established price containment measures that would come into effect to mitigate excessively high prices. We are committed to regular public updates on the status of AB 32 implementation, including the cap-and-trade regulation.

B-74. Comment: The time frame for implementing the cap contemplates virtually immediate changes to business as usual in California. The changes do not allow for rational planning or for alternative strategies for achieving the implicit emissions limit. For example, a utility may need to plan for additional renewable energy purchases, which may require new facilities to be constructed. There is a 2-3 year planning cycle for such construction and renewable generation. Independent power producers may need to purchase offsets (instead of allowances) in order to continue operation at past levels. Offset projects take some time to organize and receive approval. Fundamentally, if 2012 is the first compliance year, the only available option for compliance other than purchasing allowances is to reduce output or curtail operations. (HOR)

> **Response**: We moved the compliance start date from 2012 to 2013 to ensure that the regulatory elements are in place and fully functional. The regulation provides flexibility in compliance via many mechanisms, including purchasing allowances and the use of offsets.

B-75. Comment: The rationale presented for a cap and trade scheme covering 85 per cent of California's GHG emissions is that it establishes a price signal to drive long term investment in cleaner fuels and energy efficiency encourages implementation of the lowest-cost abatement first, which gives flexibility to covered entities. However, based on global experience of Cap and Trade schemes, these assumptions are highly questionable. Carbon prices are incredibly volatile and prone to major crashes–in large part because “carbon” is a commodity that does not exist as a single entity outside of the numbers displayed on trading screens. The result is that these markets emit, at best, a very weak signal. The practice of “hedging” carbon permit prices against shifts in energy prices and currency exchanges cancels out this signal altogether In theory, a “robust carbon price” would make dirty industry uneconomic. In practice, such a price is of a different order of magnitude to current prices–mainstream economists estimate ten times or more of what it currently trades. A high and stable price would at best encourage companies to invest in changes that push the problem off their books. Such a price could not solve the problem of “locking in” pollution. In chasing after the cheapest short-term cuts, cap and trade tends to encourage quick fixes to patch up outmoded power stations and factories–delaying more fundamental changes. (CTW)

> **Response**: We agree that a stable price signal on fossil based fuels is necessary to drive long-term investment in cleaner fuels, to encourage energy efficiency, and to do so in the most cost-effective manner. The cap-and-trade regulation includes a number of features designed to provide some predictability in cost, including limited use of offsets, banking, and an allowance reserve and reserve price. We do not agree that the California market will see similar outcomes as existing carbon markets. Lack of a high or stable price signal in the other markets was the result of over allocation of allowances, which was the result of inadequate information on actual emissions. We used several years’ worth of verified emissions data to determine the number of allowances that will be made available. It is unlikely that the California market will be over allocated.
>
> The price containment mechanisms along with an entity’s ability to hedge, provide further price stability should non-controllable events occur, such as a prolonged drought or rapid economic expansion. We believe a market-based approach is best as it provides a demand-side response to an allowable price signal across the entire economy. We believe that the price signal established through the cap-and-trade program would provide an incentive for investment in energy efficiency and clean fuels. The design of the cap-and-trade program provides a reasonable compromise between achieving emissions reduction requirements while not significantly affecting the economy.

Low Carbon Fuel Standard

General

B-76. Comment: In April of 2009, CARB issued Resolution 09-31 on the Low Carbon Fuel Standard, which directed CARB staff to “evaluate as part of the Cap and Trade rulemaking whether displacing petroleum transportation fuels with electricity leads to a cross-sector shift in GHG compliance obligations.” SCE urges CARB to conduct a long-term study on the cross-sector shift in order to make educated policy decisions early on, especially as plug-in electric vehicles steadily increase their market share. (SCE1)

> **Response:** Notwithstanding potential local or regional impacts on electrical infrastructure, staff has estimated that displacing petroleum-based transportation fuels with electricity would not lead to a significant cross-sector shift in GHG compliance obligations before 2020 because the electricity projected to be supplied to the State's electric vehicle fleet in the foreseeable future is estimated to be less than two percent of the total State vehicle fleet's energy needs. For example, in the California Energy Demand 2010-2020 Adopted Forecast, the California Energy Commission estimated that electric vehicles would consume 4,400 gigawatt-hours (GWh) of electricity in 2020; whereas, the total estimated electricity demand in 2020 would be 320,000 GWh. Additional long-term study may be justified to further examine impacts in the 2035+ timeframe if the PEV market continues to grow.

B-77. Comment: Include appropriate reform of CEQA and air quality regulations so that low carbon fuels and technologies rapidly receive required product or facility performance verifications, certifications and permits. The responsible ARB Executive should submit periodic reports to the Board regarding obstacles, proposed solutions and degree of success. (CCC, MAZOWITA)

> **Response:** ARB does not have the authority to reform CEQA. However, we will periodically monitor implementation of both the LCFS and the cap-and-trade regulation and report to the Board periodically on implementation of these regulations.

Support LCFS Credits

B-78. (multiple comments)
Comment: In the LCFS Final Regulation Order, which became effective April 15, 2010, CARB stated that LCFS credits may be used for compliance with other GHG reduction programs, including CARB's AB 32 Cap and Trade program. CARB staff raised the possibility of linkage to the LCFS program throughout the Cap and Trade rulemaking process and discussed the possibility with stakeholders in workshops. However, the proposed regulation makes no mention of LCFS credits for compliance purposes or linkage to the LCFS program. LCFS credits will only be valuable in the Cap and Trade program during the first compliance period, before the transportation sector is added to the program. SCE supports the use of LCFS credits in the Cap and Trade program, and strongly recommends that CARB allow LCFS credits to be used for compliance purposes in the proposed regulation's Cap and Trade program. (SCE1)

Comment: Allow cap and trade allowances to qualify as credits within the California Low Carbon Fuel Standard. California's LCFS (section 95485), allowances and offset credits used for compliance within the proposed Cap and Trade program would not qualify as credits within the LCFS. The California LCFS imposes significant compliance challenges and uncertainties. In fact, the program becomes infeasible starting as early as 2014 when existing biofuel blending alternatives make it impossible to achieve mandated GHG fuel standards as currently designed. The current LCFS program allows carbon credits to transfer from the LCFS to the proposed cap-and-trade program but fails to provide the reverse exchange. CARB should adopt provisions that would allow fuel producers and importers regulated under the California LCFS to meet all or part of their annual LCFS compliance obligation with allowances and qualifying offset credits from the Cap and Trade program. This approach does not compromise the integrity of Cap and Trade or LCFS program/targets and enhances the feasibility of the LCFS. This would directionally ease some of the major compliance concerns with LCFS. Failure to adopt this recommendation disproportionately imposes large carbon costs on transportation consumers and leaves the program vulnerable to isolated market volatility dynamics. We seek the Board's resolution to improve cost-effectiveness and feasibility of the LCFS program by allowing the use of allowances and credits from the Cap and Trade program for compliance. (CONOCO)

Comment: To the extent that ARB proceeds with both the Cap and Trade and the Low Carbon Fuel Standard (LCFS) regulations, ARB should provide a means by which allowances and/or credits may be used and transferred between programs to satisfy compliance obligations. The LCFS program will potentially be the most cost-intensive program under AB 32, second only to the proposed Cap and Trade regulation. Depending on the availability of “approved crudes” not classified as High Carbon Intensity Crude Oils (HCICO), coupled with the availability and costs associated with blending biofuels, the impact to Valero of the LCFS regulations could easily reach $100s of millions by 2020. Initial costs of this program in 2011 alone may exceed $10 million. These costs are in addition to the Cap and Trade costs. The ability to find cost-effective GHG emission reductions that could be commensurate with the carbon reduction requirements under the LCFS will be critical for an industry facing costs of this magnitude. The LCFS program, through the life-cycle analysis of feedstock and fuel products, reduces the obligations for carbon reductions into a simple total tonnage of CO_2. From a scientific standpoint, nature is indifferent as to the means of emission reductions, whether a renewable fuel, an offset, or some other emission reduction within a facility’s operation. Consequently, there is no scientifically justifiable reason why a reduction that generates a credit under the Cap and Trade cannot be applied for compliance purposes to the reduction obligations under the LCFS. Transportation fuel carbon is already planned for inclusion under the statewide carbon cap. The flexibility to apply emission reductions interchangeably between programs will have no impact on the cap, compliance, or the reduction obligations required by AB 32, should ARB proceed with massively expensive program. (VALERO)

Comment: The regulation is silent on the question of allowing credits created pursuant to California’s LCFS to be traded within the proposed cap and trade structure, indicating that such trades are not contemplated in the structure. The OWG has previously supported inclusion of LCFS credits in the cap and trade, and remain convinced that LCFS credits should be allowed in the cap and trade structure, at least for the years prior to the inclusion of the transportation sector under the cap. (OFFSETSWG1)

Comment: Why are credits not fungible between the LCFS and Cap and Trade? Given the importance of transportation fuels in the market, it would seem prudent to evaluate and resolve this aspect of AB 32 carefully and only after extensive study. (WSPA1)

Comment: The issue of linking cap and trade credits with the low carbon fuel standard needs some additional conversation. (WSPA2)

Comment: SCE requests that CARB clarify whether LCFS credits can be used in the cap-and-trade program, as LCFS credits can provide another way for covered entities to meet their compliance obligations. (SCE1)

Comment: ARB has already developed protocols under the LCFS. These protocols can also be used to develop credits under the Cap and Trade program. This will provide additional economic stimulus for the development of alternative low-carbon fuels. (WM1)

Comment: CARB has already adopted protocols under low carbon fuel standard. Make those credits available to transfer into the cap and trade system as soon as possible. That will further provide a value for those kinds of reductions. (WM2)

> **Response:** Currently, the LCFS allows the export of LCFS credits to other programs that will accept them, but it does not allow importation of credits into the LCFS program. This is to ensure that the fuel providers act appropriately to provide low-carbon fuels. As required by the LCFS regulation, staff is conducting a formal review of the LCFS and may consider the credit options in the LCFS, including an assessment of credit options.
>
> We do not believe it is appropriate to allow LCFS credits to be transferred into the cap-and-trade system. Credits have different definitions in each regulation and are subject to different protocol requirements. For example, the LCFS looks at lifecycle carbon intensity, while the cap-and-trade program looks only at direct emissions. If credits were fungible between the two systems complex emission reduction overlaps, or unintended double-crediting for reduction could occur. Currently, the cap-and-trade program considers reductions in direct emissions as the result of compliance with LCFS to be recognized and counted as a benefit toward a capped entity's compliance obligation. We prefer to maintain the simplicity of this overlay and not complicate things with interchangeable credits between the two systems.

Linkage

General

B-79. Comment: IETA is pleased to see ARB's Cap and Trade draft regulations consider the issue of linkage, not only with other WCI jurisdictions but with other regional and international schemes as well. Based on evidence and experience, linking regional and worldwide emissions trading markets would provide greater market liquidity while encouraging the realization of the most cost-effective reduction opportunities for GHG emissions. (IETA1)

> **Response:** No response is necessary

B-80. (multiple comments)
Comment: The proposed regulation is doomed to failure because of the limited participation by other jurisdictions and the demise of a federal cap and trade program. The California only program, which the Board appears determined to pass before it is fully baked, poses huge risks of harm to jobs and the California economy due to among other factors, economic leakage. Moreover, the associated GHG emissions leakage will undermine any integrity the Board may have hoped for in the program. We believe that many proposed aspects of the program will unnecessarily exacerbate this risk and CARB should give full consideration to both the limited linkage to competing jurisdictions and the incompleteness of the regulation and put this measure over until it is complete and there are enough real trading partners to avoid massive leakage. This damn the torpedoes, full speed ahead whether the regulation is complete or not mentality reminds us of the ill-fated electricity deregulation scheme and we believe that CARB's rush to pass the Cap and Trade Regulation before it is ready will blow up, just as deregulation blew up, as soon as allocation gives way to auction with the only question being how dire the resulting economic consequences. (PLOTKIN)

Comment: IETA's membership is appreciative of progress in adapting flexible approaches and would like to stress the importance of the considering future linkages to comparable markets that have broadly symmetrical regulations. (IETA2)

Comment: CERP supports linkage with other programs and urges ARB to move forward with linkage with qualified programs as soon as possible in 2011. (CERP1)

Comment: The regulation needs to demonstrate a greater sense of urgency on linking with other programs. This should include a specific timeline for evaluation and decision, and consideration of other cost control measures should significant and timely linkage not be accomplished. CARB should state in the resolution (or elsewhere before adoption of the regulation), what specific programs will be considered for linkage, and the timeline by which decisions on specific linkages will be rendered. CARB must accept that if no linkage is attained by a date certain early within the first compliance period, then a reconsideration of linkage criteria should occur and/or other, additional cost-control measures (such as additional use of offsets) should be implemented. (BP)

Comment: The ARB Board Resolution adopting final AB 32 regulation should reflect the Staff Report's statement on the importance of linkage and offset availability. The Staff Report recognizes the importance of California linking to other cap and trade programs but the regulation itself does not yet establish a path to achieving that linkage. We believe that strong support from the Board is needed to ensure that linkage with WCI partners in 2011, and linkage with the EU after 2013 can become a reality. (CHEVRON1)

Comment: If a California cap-and-trade program is linked with others through the Western Climate Initiative (WCI), California should negotiate reciprocity with other WCI participants. (NEXTERAENERGY)

Comment: The Western Climate Initiative (WCI) is not yet fully in place as originally proposed to be an integral link for California's Cap-and-Trade. (SDCHAMBER)

Comment: Linkage to WCI and other Cap and Trade Programs is mentioned in the Cap and Trade Regulation; however such linkages are not expected to be in place until late 2011. To date, California and New Mexico are the only states who intend to participate in the WCI, and New Mexico's plans for participation are subject to change. A California only Cap-and-Trade Program in lieu of a regional program will be too restrictive and limited, and should not be implemented until other state partnerships are in place. (MWDSC1)

Comment: At this point it appears the only imminent linkage is at the regional level with the WCI, which can only happen if other participants can agree to the program's implementation and will be ready for the 2012 start date. Without linkage to other programs, a California-only Cap and Trade program ignores the opportunity for economic growth and puts California at significant economic risk. It is important that CARB create a program that California can seamlessly interface with the WCI partners with ultimate linkage to a national and international platform. (CALCHAMBER1)

Comment: ARB should ensure that its Cap and Trade program will link directly to a U.S. federal program and to regional programs such as WCI. Although California has been a leader with respect to climate change, California businesses will suffer and environmental goals will not be met if regulators do not closely coordinate and link market programs. CLFP believes that a "go-it-alone" approach is not a viable option. (CALFP1)

Comment: The Council is encouraged that the California Air Resources Board envisions linking its Cap and Trade program with other WCI Partners to create a regional market system. We are also encouraged by indications that California is discussing opportunities to link with the Cap and Trade program in the Regional Greenhouse Gas Initiative (RGGI) states. These linkages will be critical for consistency among programs and will facilitate what we hope will be an eventual transition to a national program. (BCFSE)

Comment: We are very concerned about the proposed regulation because of the limited participation by other jurisdictions including those in WCI and the dim prospect of a federal cap and trade program anytime on the horizon. This poses huge risks of harm to jobs and the California economy due to economic leakage, and the associated GHG emissions leakage would undermine integrity of the program. (AB32IG)

Comment: In designing its program, California should strive for compatibility with the European Union trading system and offset policies. Given the importance of interstate and international trade to California's economy, we must design our program to ensure that California companies are appropriately positioned to compete under any future federal or international program. (LADWP1)

Comment: CARB has always maintained that in order to be effective the cap and trade program must be part of a regional multi-state effort, yet the regulation before you does not propose linking to any specific programs outside California at this time. If widespread equitable linkage cannot be accomplished, serious consideration should be given to postponing a cap and trade regulation. (CAHISPCHMBR)

> **Response:** We recognize the importance of linkage with other jurisdictions to provide an additional cost containment mechanism, prevent leakage, and secure additional GHG reductions. Staff analyzed the potential of a cap-and-trade program on California businesses, and the proposed regulation includes methods to reduce competitiveness loss through the allocation process.
>
> The proposed regulation establishes a framework for linkage and considers the issue of linkage with other GHG emissions trading systems. Subarticle 12 of this regulation provides possibilities for linkage, including procedures to evaluate external GHG emissions trading system. Establishing linkage with other programs will require further assessment and establishment of a formal rulemaking process under the APA before allowances and/or offset credit from an external program can be used for compliance with this regulation. When evaluating whether we should link to another program, we will consider criteria that the potential linked program must meet, to ensure that the linked program has provisions for cost-containment, market tracking, registration, monitoring, reporting, verification, and enforcement that are reliable and sufficient to ensure its environmental integrity. California is a partner state of WCI and has been actively involved in WCI activity and the design element. We are looking to link to WCI partner states and provinces that may be ready to implement their cap-and-trade programs in the near term. We modified the first compliance year from 2012 to 2013 to ensure a robust program. The WCI partner jurisdictions—Quebec, Ontario, and British Columbia—are in the process of developing and adopting cap-and-trade programs.

To ensure harmonization with other national programs, our mandatory GHG reporting requirements are in alignment with the U.S. EPA mandatory program, where appropriate.

Duplicative Regulations

B-81. (multiple comments)
Comment: Southern California Edison believes the nature of climate change problems would best be addressed at a national or international level. While SCE supports the use of a cap and trade program to efficiently reduce emissions, we remain concerned that, as proposed, the market design and the operating rule will not work as expected. The proposed rules are extremely complex and today have not been adequately tested. Of course, California learned the hard way from the electricity crisis that the complexity of an untested creates opportunity for market manipulation. SCE suggests the Board should take time to get this market right. We hope the Board will instruct staff to condition the start of the cap and trade market on some crucial readiness criteria which include not at a minimum developing some market simulation and testing processes and implementing them into the market monitor prior to the beginning of the program. (SCE2)

Comment: The resolution should state the Board’s intention that the AB 32 program, as a robust economy-wide carbon cap and trade program, provides the best approach to regulate California’s GHG emissions and to encourage strategic low-carbon technology development and that the overlay of federal GHG regulation would be neither necessary nor beneficial, particularly in light of the additional cost, time delay and multiple agency administrative resources that implementation of such duplicative federal regulations would require. (CCC, MAZOWITA)

Comment: CCEEB is concerned that California businesses will be subject to duplicative GHG regulations from the state and federal government. CCEEB recommends that ARB clearly state their intent to not subject California's businesses to duplicative GHG regulations. (CCEEB1, CCEEB2)

Response: We recognize the importance of harmonization between State and federal GHG emissions reduction requirements. In Resolution 10-42, the Board directed the Executive Officer to work with U.S. EPA on the development of a federal regulatory framework to grant delegation or equivalency to California’s climate change program where appropriate.

We will begin to test market infrastructure components in 2012 and compliance requirements for covered entities start in 2013. This change ensures that all central elements of the program are developed and tested in 2012 before we move into the first year of compliance in 2013.

Additionally, our mandatory GHG reporting rule is harmonized with the U.S. EPA mandatory reporting rule. In the event that the U.S. EPA cap-and-trade program becomes available, our cap-and-trade program design element can easily transit into the U.S. EPA program.

B-82. Comment: The cap and trade program under AB 32 is likely to be equally or more stringent than the command and control regulations under the Federal CAA scheduled to come into effect in 2011. ARB should consider proposing that reductions under AB 32 will constitute conformance with the CAA. (WSPA1, WSPA2)

Response: We are working closely with U.S. EPA on how U.S. EPA will implement greenhouse gas measures, including equivalency for state greenhouse gas emissions reduction programs.

C. ALLOCATION OF ALLOWANCES

This section includes comments and responses about how allowances (permits to emit CO_2e) are distributed for free to eligible covered entities, and primarily refer to sections 95870 and 95890–95893 of the regulation. Major topics within this category concern the amount of and justification for free allocation, benchmarking (especially the methodologies and data used to develop the benchmarks, and sector-specific concerns about the methodologies), and leakage (especially concerns about the risks and monitoring of leakage). Comments concerning free allocation of allowances to the electric distribution utilities are found in the section entitled “Electricity.” Comments concerning the use of auction proceeds are found in the section entitled “Use of Auction Proceeds.”

Free Allocation

Support Free Allocation

<u>No/Little Auctioning at Start</u>

C-1. (multiple comments)
Comment: IETA would like to stress the importance of avoiding the temptation to have extremely high auctions at the onset of the program. (IETA2)

Comment: A system that imposes costs immediately, as a result of an auction or taxes or other immediately effective cost increases, will drive businesses and perhaps individuals out of California. Allocating allowances for free to regulated entities maintains the integrity of the cap, while avoiding immediate economic incentives to leave California. (HOR)

Comment: A well-designed auction system may be the optimal approach to reach our carbon reduction targets. However, full auction of allowances at the beginning of a cap- and trade-program may be too abrupt a transition, and may pose high short-term costs to capped companies. A free allocation system, on the other hand, should reward companies that have already made significant investments in energy efficiency and carbon reduction, and should not penalize those that produce goods in California. (LADWP1)

> **Response:** We agree and proposed such an allocation/auction system in the Staff Report. The purpose of the allocation of allowances is to provide transition assistance upon the start of the cap-and-trade program (via distribution of free allowances at the start of the program), prevent leakage (by continuing free distribution for activities prone to leakage), and encourage in-state production (by distributing allowances based on production). We believe it is especially important, given current economic conditions, to provide regulated entities the opportunity to invest in low-carbon technologies. The comments address leakage, which we considered prior to the publication of the Staff Report. Our

leakage analysis is described in more detail in Appendix K of the Staff Report. We are committed to continue to monitor leakage throughout the implementation and progression of the cap-and-trade program. We believe the proposed regulation is designed to minimize leakage to the fullest extent feasible.

Rate of Decline of Free Allocation

C-2. (multiple comments)
Comment: Dow is concerned about the rapid decline in allocated allowances. While approximately 97 percent of allowances are to be initially allocated to industry (including over 50 percent to electric utilities) during the program's first compliance period (2012 through 2014,) this number decreases to 42 percent by 2020. Dow is supportive of the high initial allocation, but believes the 55 percent decline in allocated allowances in only six years is problematic. At the rate proposed by ARB, industry will find it very difficult to adjust to the increased costs of auction, threatening competitiveness, jobs and consumer energy prices. Significant time and capital investment are needed to meet long-term emission reductions goals and transition California to a lower-carbon economy. Dow recommends exponentially phasing in more auctioning over a longer period time, where initial auctions would be small and gradually increase at a steeper rate. This will help participants acclimate to the market, keeping costs down and improving efficiency. (DOWCHEM1)

Comment: Significantly limit the reductions in the Assistance Factor for stationary sources. Arguments regarding high vs. medium trade exposure notwithstanding, limiting the changes in the Assistance Factor to one percent or two percent per compliance period would provide the refining sector more of the trade exposure protection we seek, but would also limit the financial impacts and allow for resources to be spent on actual reductions as opposed to simply buying carbon allowances, without providing any tangible environmental benefit. (VALERO)

Comment: IETA is concerned about the rapid decline in allocated allowances. ARB is planning on allocating the bulk of allowances to the utility and industrial sectors beginning in 2012. IETA recommends phasing in the decline in allocated allowances over a longer period time, where initial auctions would be small and gradually increase at a steeper rate. This will help participants acclimate to the market and permit time for large capital investments to yield emissions reductions, keeping costs down and improving efficiency. (IETA1)

Response: We believe the auction system is the fairest and most transparent way to distribute allowances. This is supported by the recommendations of the Economic and Allocation Advisory Committee. The auction will also help maximize incentives for continued investment in clean and efficient technologies and provide revenue that can be reinvested for public benefit. The allocation provision of the regulation was designed to provide a soft start for the cap-and-trade program and the transition toward a greater reliance on auctioning is necessary as transition and leakage risk decreases over time. We believe the rate of transition from free allowances to auction is appropriate.

Method of Free Allocation – Historical, Percentage of Cap

C-3. Comment: Allocate allowances to regulated entities in rough accordance with their past usage. No regulated user should be required to submit allowances without receiving an allocation representing a "share" of the cap.

Issue allowances for free to all regulated entities reflecting a share of the cap. The value of allowances is and should be *driven* by the established limit or cap on overall use. (HOR)

Response: The commenter's request to distribute allowances in accordance with past usage is a "grandfathering" approach. This approach rewards entities with high emissions. Instead, our proposal to distribute allowances based on an efficiency-based benchmark rewards entities who have taken early actions to reduce greenhouse gas emissions. We believe it is critical to allocate allowances to industrial entities at risk of emissions leakage. We analyzed the potential for emissions leakage by looking at emissions intensity and trade exposure. To determine which industry sectors were at risk of emissions leakage, we developed a methodology to assess a sector's emissions intensity and trade exposure and presented this in Appendix K of the Staff Report. We also stress the importance of the proposed transition toward a greater reliance on auctioning which will help maximize incentives for continued investment in clean and efficient technologies and provide revenue that can be reinvested for public benefit.

Free Allocation for Duration of Program

C-4. Comment: We recommend CARB allocate allowances without charge throughout the duration of the program. The implementation of this recommendation will foster a more robust liquid emissions market. Requiring sources to purchase an increasing quantity of credits through state sponsored auctions will unnecessarily increase the cost of the program, prompt facilities to move out of state, and render sources less able to develop and implement controls. Instead, CARB should utilize a simple, "free" allocation system. Under this proposal, sources are provided a declining emissions cap, or allowance checkbook. For sources in operation in 2011, the cap would be at a level that is just shy of their 2011 emissions. New sources are either given a special allocation, which may be set aside from the initial allocation, or allowed to buy surplus allowances from existing sellers.

We support the use of free allocations as opposed to 100 percent auctions. Historically, successful emissions trading programs have relied upon allowance distribution systems. Here, each source in operation at the commencement of the program is given an initial allocation that starts in year one and extends (at a declining rate) through the program's duration. We are unaware of any successful pure auction system where existing and new sources secure their initial and ongoing allowances through an auction. The free distribution allocation method puts tons into circulation, and rewards sources that discover they can benefit economically by reducing their allowance needs and selling their surplus. In contrast, a primary auction is another form of a carbon tax; one that delivers revenues to the government without the obligation to make prudent decisions regarding the use of such monies. An allocation system gives sources their allocations well into the future (in some cases, indefinitely). In contrast, an auction forces participants to purchase near and long term allowances, begging the question as to how sources will recover these costs (of course, the ultimate bill is delivered to the customer who purchases the products) or finance emissions reductions. In addition, the lack of regulatory certainty wreaks havoc with capital planning by sources to install the very technologies that could achieve long term emission reductions.

Market liquidity and diversity will be relatively higher under a free allocation system and lower under an auction system. Giving 30 years worth of allowances to covered sources will ensure that sources have a base amount of allowances that they can either use or sell. The availability of these allowances, especially at the outset of this program, allows sources to purchase in the spot market as well as execute options, leases, swaps, and forward transactions for near term and future year allowances, all with variable terms and conditions and counter party credit quality. Withholding allowances, and making them only available through government sponsored auctions will have an unfavorable impact on liquidity, cost to society of the program, and how great a benefit to the environment is realized. An auction drains cash from emitters, resulting in less available capital to invest in reducing emissions. An auction puts sources in a cost minimization mode (they do what’s necessary to acquire the least amount of allowances at the outset), rather than a profit maximization mode (‘over-compliance’ can free up allowances that can be sold) that comes with a free allocation. An auction severely disadvantages existing emitters over new sources. In an auction, new entrants have the choice of tailoring their purchases and facility designs in perfect synchronization. Existing polluters have plants designed for an environment where emissions were unregulated. In contrast, new entrants have the unfair advantage of being able to design their plant for the new environment. Auctions discriminate against existing emitters who have a higher cost-base. (CANTORCO2E)

Response: We believe the auction system is the fairest and most transparent way to distribute allowances. This is supported by the recommendations of the Economic and Allowance Advisory Committee. The purpose of the initial allocation of allowances is to provide transition assistance and minimize leakage upon the start of the cap-and-trade program. The proceeds from the auction system will provide revenue that can be reinvested for public benefit and used to invest in emerging technologies to help California meet our long-term emissions-reductions goals. We believe the design of the cap-and-trade program demonstrates certainty of emissions reductions, and that we will meet the goals of AB 32 and specifically, the 2020 target.

Free Allocation so as Not to Be Taxed

C-5. Comment: I would suggest that you allocate allowances in a way that doesn't cost industries anything. They should be able to rely upon the stream of credits and plan around it. If you impose an auction requirement upon them, it will be taxable to contribute to leakage as businesses consider moving out of state to avoid these costs. (MARGOLIS)

Response: The proceeds from the auction system would provide revenue that can be reinvested, as appropriated by the legislature, for public benefit and used to invest in emerging technologies to help California meet our long-term emissions-reductions goals. We analyzed the potential for emissions leakage and developed a methodology to assess a sector's emissions intensity and trade exposure. We assigned the appropriate level of free allocation to minimize leakage and provide transition assistance. We believe that greater levels of auctioning are appropriate as transition risk diminishes.

Free Allocation Combats Leakage

C-6. Comment: RCRC supports the proposed free allocation of allowances to the industrial sector. As recently outlined in a letter to you by the Southern California Leadership Council, Dun & Bradstreet estimates show that approximately 2500 companies have left the state since January 2007, taking with them nearly 70,000 jobs. History shows that when companies in unregulated sectors face heavy regulation, many of them simply relocate to other states or even other countries in order to escape the burdensome costs of compliance. We believe the free allocation proposal is a good faith effort by ARB to prevent more businesses from moving their operations out of state so that Californians can retain these jobs. (RCRC)

Response: Thank you for your support.

CO_2 Suppliers

C-7. Comment: Our Golden Eagle refinery sells CO_2, a byproduct of hydrogen we manufacture, to a third party which purifies the CO_2 and distributes it to final uses. The proposed regulation defines the point of regulations for industrial CO_2 as the supplier of CO_2 because they are involved in the sale and delivery of the gas for commercial use. Because process emissions associated with hydrogen production include all process CO_2 emissions, CO_2 purchased from hydrogen plants by CO_2 suppliers should not be subject to a requirement for allowances. Doing so would in essence double count this CO_2 in terms of the allowance calculation. (TESORO)

Response: It was never our intent to subject supplied CO_2 to a compliance obligation every time it changed hands. We modified the regulation to clarify that for CO_2 supplied in-state, the producer or extractor of the CO_2 holds the compliance obligation.

Food Manufacturing

C-8. Comment: Ag Council appreciates CARB's first three years of free allowances to avoid extreme market fluctuations. (ACC3)

Response: Thank you for your support.

Hydrogen as Transportation Fuel, Facilities (Non-Refinery), and Refinery Based

C-9. (multiple comments)
Comment: Whereas other distributed transportation fuels will not be subject to a compliance obligation for their inherent carbon-footprint until the second compliance period, the compliance obligation resulting from production of hydrogen as a transportation fuel will be imposed immediately under the first compliance period. Air Products encourages CARB to provide free allocation of allowances for such hydrogen fuel to prevent an increased barrier for deployment of this long-term transportation solution.

Allowance allocations must be provided for hydrogen production, regardless of it source —captive or third-party supply. Any presumption that third-party hydrogen suppliers can simply pass-on the full cost of allowances required to satisfy their compliance obligation to their respective hydrogen customers ignores the complexity, limitations, variety of commercial agreements/arrangements between supplier and customer. Equitable treatment can be assured by applying a consistent benchmark for, and allocating the resulting allowances to, both captive and third-part hydrogen producers.

Allowance allocations attributable to hydrogen production should be provided directly to the hydrogen producer, regardless of whether they are inside the refinery or a third-party producer. There are several reasons to support this position:

- Contractual terms limit the degree and expediency of any cost recovery (or allowance transfer), between the hydrogen producer who bears the compliance obligation and the customer for the hydrogen.
- Where a single third-party hydrogen producer supplies multiple refinery customers from one or more plants, connected by a pipeline distribution system, allocation of the hydrogen producer's compliance obligation between multiple customers could require disclosure of confidential business information between customers, creating anti-trust concerns.
- Should an interim allocation benchmark approach be required (as noted above), direct allocation of allowances based on the proposed "model" benchmark is based on hydrogen production, not consumption—hence allowances would be directed to the hydrogen producer.
- Allowance allocations made to compensate hydrogen producers for hydrogen used as a transportation fuel (see comment below) can only, logically, be made directly to the hydrogen producer. Making all allowance allocations for hydrogen production directly to creates more consistent treatment under the program.

- Allocating allowances directly to the hydrogen producer is consistent with the EU ETS program and allows core consistent and effective linking of cap and trade programs in the future. (APC)

Comment: The final California cap and trade regulations should allot allowances for stand-alone hydrogen plants not associated with refineries. Section 95811(a)(4) of the proposed rule identifies operators of hydrogen production plants as covered entities and section 95890(a) states that a covered entity from the industrial sectors listed in Table 8-1 shall be eligible for direct allocations of California GHG allowances. However, hydrogen production plants are not listed in Table 8-1. Instead, Appendix K, Leakage Analysis, p. K-6, includes hydrogen plants as an associated process of petroleum refining: ("These plants and activities [petroleum refining] include hydrogen plants"). Table K-2: Sector Classification for Emissions Leakage Analysis, p. K-7, lists "Petroleum products mfg" as an aggregated sector and includes "industrial gas/hydrogen plant" as the description of one of these associated processes. And Table 8-1: Industry Assistance, assigns a "Leakage Risk" to "petroleum refining" as "Medium" and provides a 100 percent Industry Assistance Factor ("AF") for the first Compliance Period from 2012-2014; 75 percent AF for the second Compliance Period (2015-2017); and 50 percent AF for the last Compliance Period (2018-2020).

Praxair's Ontario hydrogen plant does not supply refineries. This plant, and any other company's stand-alone merchant hydrogen production plant that does not serve a petroleum refinery, will not have an opportunity to seek from a host petroleum refinery any allowances that have been directly allotted by CARB to the refinery. Because merchant hydrogen production is not listed as an industry eligible for direct assistance, our Ontario plant will be compelled to acquire allowances at auction or from third parties in the secondary markets, raising the cost of our hydrogen product.

Praxair's Ontario plant supplies liquefied hydrogen to customers in the aerospace/defense, steel, and glass manufacturing industries, among others. The U.S. government is a major customer for aerospace and defense-related needs. More than 50 percent of the Ontario plant's production used to meet customer demand outside of California, making this plant vulnerable to "activity shifting leakage" (e.g., production-related emissions shifting to out-of- state competitors not subject to the AB 32 program) from plants not subject to the GHG compliance costs. Moreover, there will be elevated competition for customers located within California from production occurring outside the state where production plus transportation costs can meet or beat in-state production and delivery costs.

Because hydrogen is such a light compound compared to carbon dioxide, for every ton of hydrogen product produced in a steam methane reformer ("SMR") there are ten tons of carbon dioxide byproduct. This energy-intensive production relationship magnifies the direct and indirect GHG compliance cost impact on Praxair's final price to its hydrogen customers. So, assuming the CO_2 allowances' initial cost in 2012 is $10 per metric ton (the floor price), the corresponding impact on our hydrogen product price is $100 per ton. At full production, this cost could amount to almost a million dollars annually, with such compliance cost burdens increasing as the presumed value of allowances increases and the allowance cap decreases over time.

Should Praxair not be allocated free allowances, the high incremental compliance costs for purchasing allowances will likely prompt two results: 1) Praxair buying allowances and incurring substantial incremental costs for product sold to customers, thus rendering our business uneconomic; and 2) our customers obtaining hydrogen from out-of-state producers, at substantial increased costs to the customer, but at the same time undermining our continued business operation viability. Increasing demand for out-of-state supply also has the unintended consequence of increasing GHG emissions from the liquid hydrogen- bearing tractor trailers that will need to travel substantially farther from states into California to supply in-state customers. Either outcome is inconsistent with some of the Act's stated purposes in section 38562: "to achieve cost-effective reduction" and "to minimize leakage."

Praxair met with CARB Staff on Monday, December 13, 2010, to discuss this leakage issue. We are currently in the process of compiling additional data as requested by CARB staff to help with the leakage risk analysis. We anticipate providing the information and continuing our dialogue with staff on the impacts to Praxair's activities and the justification for inclusion in Table 8-1.

At this time Praxair requests that the Board's Resolution adopting the draft regulations give specific instruction to allocate free allowances for stand-alone hydrogen production plants as a "High" Leakage Risk and to include such plants in Table 8-1 in Appendix A of the proposed rule. (PRAXAIR)

Comment: Air Liquide Large Industries addresses CARB's failure to allocate emissions allowances to hydrogen production facilities associated with refineries. Free allowances that are allocated for particular emissions within the refining sector (hydrogen plants) should be allocated to the party generating the emissions. Under the rule, Air Liquide and its competitors would be required to purchase allowances for emissions from their refinery-based hydrogen plants, and depending on the terms of their long-term contracts with their refinery customers, may or may not be able to recoup the cost of purchasing those allowances. CARB's treatment of refinery hydrogen plants and independent hydrogen plants creates potential unfairness and inefficiencies which would not exist if allowances were allocated to each party generating emissions associated with petroleum refining. We suggest the following:

1. The proposed regulation should be revised to avoid interfering with long-term contracts. CARB has recognized the importance of protecting parties of long-term contracts in the electric power generation industry, noting in Appendix J that these parties "may require special treatment." CARB should protect parties to such long-term contracts who may be unable to pass the costs of purchasing allowances through to their customers by allocating allowances to them.
2. CARB should encourage the efficient operation of independent hydrogen plants. CARB's allocation to refiners but not to independent hydrogen plants associated

with refineries could disrupt the efficient operations that have developed between refiners and independent hydrogen plants at California refineries.

3. CARB should avoid creating disincentives to efficient relationships between refiners and independent hydrogen plants. The proposed regulation may disrupt these efficient relationships by favoring the “in-sourcing” of hydrogen production by refiners. For example, if the refiner receives free allowances for the operation of its hydrogen plant but is required to reimburse a hydrogen plant operator for allowances (under a long-term contract that obligates the refiner to pay such costs) when it purchases hydrogen from an independent hydrogen plant, then the refiner may have an incentive to use its own hydrogen production facilities, resulting in less use of the most efficient, state- of-the-art facilities and leading to increased GHG emissions.
4. CARB should freely distribute to hydrogen plant operators to avoid any disincentive for refiners to use the most efficient hydrogen production facilities. The perception that the program unfairly imposes costs on parties to long-term contracts and causes economic harm to the most efficient producers of hydrogen would undermine the Cap and Trade program. These negative consequences will be avoided by allocating allowances to refineries and to independent hydrogen plant operators on the same basis.
5. CARB should accommodate existing long-term contracts, eliminate any incentives for inefficiency, and promote the use of efficient hydrogen plants associated with refineries by allocating allowances for particular emissions to the party generating the emissions. Minimally, CARB should allocate allowances to independent hydrogen production facilities associated with refineries in order to promote and avoid interference with long-term contracts, and allocate allowances to hydrogen facilities associated with refineries that are subject to long-term contracts that do not allow recoupment of the costs until the current contracts expire or are modified. (ALLI)

Response: We agree and recognize that equity issues exist between allocation to third-party production of hydrogen gas sold to petroleum refiners and refinery-owned hydrogen production. We believe that employing the CO_2 Weighted Tonne (CWT) approach for the refining sector is the best way to address this issue. We modified the regulation to present a separate benchmark for hydrogen gas based on the amount of hydrogen gas produced in Table 9-1 in section 95891(b). This value will be used to allocate to third-party hydrogen facilities. This value is derived from the hydrogen CWT function and is identical to the value that would be applied to refinery-owned hydrogen production under the CWT approach.

In addition, we modified the regulation to allow for a different allocation to liquefied hydrogen production facilities in the future if necessary. If, in the future, any carbon costs from purchased electricity are included in consideration of the product benchmark values, the high level of indirect emissions from liquefaction of the hydrogen would likely lead to a different benchmark value for liquefied hydrogen. The current framework could also allow for a change in the leakage risk classification for liquid hydrogen based on any new information that may arise as we continue to analyze leakage risk per the direction in Board Resolution 10-42.

We recognize the potential of hydrogen as a clean transportation fuel. However, we do not agree that it is appropriate to provide an explicit incentive for this use of hydrogen through free allocation. The purpose of allowance allocation is not to “pick winners” among the many greenhouse gas reducing technologies that may become more widely used in response to the carbon price signal created by the cap-and-trade program.

Natural Gas

C-10. (multiple comments)
Comment: ARB should administratively allocate allowances in a manner that fully recognizes the advantages of life cycle energy efficiency and the emission reductions associated with avoiding energy loss during the process of electric generation and distribution. The allowances allocated to each natural gas local distribution company (LDC) should be based on a percentage of natural gas deliveries reported under mandatory reporting. The formula used to calculate allowances should take into account increased usage of natural gas caused by customers who switch from electric appliances to gas fired appliances in order to avoid energy loss caused by consumption of fossil fuels for electric generation. More importantly, the allowance allocations should recognize the potential for end users to consider emission reduction opportunities associated with source energy consumption as recognized by the U.S. Department of Energy (Federal Register, Vol. 75, No. 161, Friday, August 20, 2010). Southwest would prefer that allocations be based upon 10-year weather-normalized usage data rather than the proposed 3-year normalization.

If the allowance calculation formula does not consider the emission reductions caused by switching from inefficient electric generation to direct combustion of fossil fuels by gas fired heat pumps (GFHP), the new GFHP technology will be lost from the limited opportunities for natural gas customers to have a real impact on reduction of GHG emissions. The cap and trade regulations may expose small end users of natural gas to greater price risk than small end users in the electric sector since there are fewer mitigation options; however, this price impact does not seem to correlate with significant reductions in the use of natural gas.

ARB should directly allocate allowances to natural gas LDC based on the sector’s proportionate share of the total capped sector emissions, giving consideration to increases in the use of natural gas as an end-use fuel to increase overall efficiency and achieve corresponding reductions in GHG emissions. Gas LDCs are rate regulated by the CPUC or a local governing board, so any increased costs associated with the issuance or purchase of allowances must be approved for recovery by the CPUC. As such, ARB can be assured any allowances provided will be used to further the purposes of AB 32 and for the benefit of small gas consumers. Further, rates can be structured to provide appropriate price signals. Most natural gas LDCs have low income customer programs that provide a bill discount. Without an administrative allocation of allowances to the natural gas sector, these low-income customers will likely experience rate increases from the incorporation of the cost of allowances. (SWGASCORP)

Comment: Consider allowance allocation to natural gas suppliers in ways that protect low-income natural gas consumers. The thoughtfulness that has and will go into the proposed allocation and ultimate use of allowance value for the utility and industrials sectors needs to be applied to the natural gas sector as well. The basic goal should be to avoid price spikes for low-income consumers through free allocation or impact mitigation (e.g., dividend). The guidance in the proposed rule does not make it clear that at least some of the value of allowances will be used to protect natural gas customers. (EDF1)

Comment: If ARB wants to subject small natural gas customers to the Cap and Trade Program, then it is essential to allocate allowances to the sector to reflect the unique position of this sector. At a minimum, this means that the regulations should provide the following:

1. ARB should allocate allowance value to natural gas local distribution companies (LDC) based on the sector's proportionate share of total capped sector emissions in 2015.
2. ARB should administratively allocate 90 percent of the allowances for customer benefit, which natural gas LDCs will be required to put up for auction or surrender for compliance during the period 2015-2020.
3. Revenues generated from the sale of the 10 percent of allowances in auctions should be allocated to the natural gas LDCs for the benefit of the customers to fund customer energy efficiency (CEE) and other greenhouse gas reduction programs.
4. For simplicity, it is reasonable to adopt a split of allowances for each natural gas LDC based on deliveries to customers in some multi-year historical period (e.g. 2011-2013 for allocations in 2015). Because natural gas usage varies based on different temperature conditions for a subset of customers, using a three-year average will provide an averaging of the weather conditions.

This approach is somewhat similar to the treatment of electric LDCs, except that electric LDCs do not have a compliance obligation. Without an allocation of allowance value, in the ARB modeling of AB 32, the impact of the cap-and-trade and other complementary policies was higher on small natural gas consumers than on any other sector. The impact of carbon costs associated with cap and trade may expose small end users to greater price increases than small end users in the electricity sector since there are fewer mitigation options. The modeling also revealed that this price impact appears to have limited effectiveness for obtaining significant additional GHG reductions. (SEMPRA1)

Comment: DRA recommends free allocation of allowances to natural gas distribution utilities, beginning in 2015 when they are covered under the cap and trade program, analogous to how investor-owned utilities are treated in the electricity sector. Similar to electricity customers, it is important to protect natural gas customers from significant rate impacts. (DRA)

Comment: Small natural gas customers will not be placed under the cap until 2015. PG&E recommends ARB defer its decision on how to allocate allowances to the sector. PG&E has not yet determined whether the efficiency goal for small natural gas customers is achievable and is not aware that such a study has been completed. PG&E notes that energy efficiency is the primary if not exclusive means for reducing emissions in this sector. Achieving this level of emissions depends on the rate of economic growth in the State, the efficacy of State building and appliance standards, sufficient funding for energy efficiency from the CPUC, municipal utility boards and other sources, and the effectiveness of utility-sponsored programs. PG&E recommends this issue be carefully assessed and natural gas LDC allowance allocation be reviewed at a later date in light of this assessment. (PGE1)

> **Response:** We acknowledge the above comments regarding the allocation of allowances associated with distributed use of natural gas. As indicated in the Staff Report and Resolution 10-42, we are continuing to evaluate all proposals presented. We will initiate a public process to determine how, and if, allowances should be allocated for natural gas distribution utilities, prior to coverage of the sector beginning in 2015. We note the importance of transparent price signals for fuel consumers in achieving reductions in this sector.

Refineries / Oil and Gas

C-11. Comment: The currently proposed rule would create a 100 percent free allowance allocation factor for the oil extraction industry from 2012 to 2020. We recommend that CARB auction a greater portion of allowances for this sector. The cap and trade system will set national and international precedents that should be consistent with AB 32 and LCFS goals of reducing lifecycle GHG emissions. If free allocations are given for oil production, they should be based on the most efficient producer to provide an incentive to switch from energy intensive processes such as steam injection to carbon dioxide injection and other less GHG intensive oil production processes. The current proposal could set a precedent could also be applied in other regions to provide allocation subsidies to highly GHG intensity transportation fuels such as tar sands. (ICCT1, ICCT2)

> **Response:** We believe it is critical to allocate allowances to industrial entities at risk of emissions leakage. We analyzed the potential for emissions leakage by looking at emissions intensity and trade exposure. Further, we developed a methodology to assess a sector's emissions intensity and trade exposure and presented this in Appendix K of the Staff Report. We believe the crude petroleum and natural gas extraction sector is at a high risk of emissions leakage, therefore justifying the need for a high industry assistance factor. We believe this initial allocation for the crude petroleum and natural gas extraction

sector will provide an opportunity for this sector to invest in low-carbon technologies. We will continue to evaluate leakage risk moving forward per the direction in Board Resolution 10-42. It is also important to note that the sector will not receive 100 percent free allowances. The industry assistance factor is only one component of the determination of free allowances. The other factors are the cap decline factor (which will decline two to three percent each year) and the benchmark, which is set at 90 percent of the sector's California average emissions intensity.

Transportation Fuels

Support for 100 Percent Auction

C-12. (multiple comments)

Comment: We are pleased that all the allowances for both the electricity and transportation sectors will be auctioned either directly or through consignment, creating price signals to advance technologies that are less GHG intensive. (NC1)

Comment: We support fully auctioning allowances in the transportation sector. (LUDLOW, USC1, WALTERS)

Comment: We support auctioning 100 percent of permits for transportation fuels. (CANFIELD1, CIPAL, CPC1, CPC2, FORMLETTER01, FRIEDENBERG, HANSON, ICCT1, ICCT2, SONOMAFCC)

Comment: Unlike certain other industries, the public policy justification for free allowances is not present in the application to the fuels sector. Furthermore, with a three-year delay in application, these entities are allowed time to invest in energy-efficient technologies while their emissions are recorded and reported to CARB. (GREENLINING1)

Comment: We agree with CARB's proposal to auction allowances required for the carbon content of transportation fuels delivered to end-users when they are brought into the cap in 2015. (ICCT1, ICCT2)

Response: We will continue evaluating the treatment of transportation fuels in the cap-and-trade program, including the effects of allowance distribution to different sectors within the transportation sector, and propose any necessary changes to the regulation before the start of the second compliance period in 2015. We note the importance of transparent price signals for fuel consumers in achieving reductions in this sector.

Free Allocation

C-13. (multiple comments)
Comment: If transportation fuels are included in cap and trade, create a fixed-price allowance program for the sale of those fuels. The proposed regulations place the burden of compliance for consumer transportation emissions with the owner of the fuel at the fuel terminal (see section 95811(d)). CARB assumes that fuel providers can fully embed the cost of compliance in product price. Fuel providers should not be exposed to unnecessary financial risks for consumer emissions for which they have no direct control. CARB regulations appropriately place the point of regulation for transportation consumer emissions at the fuel terminal. In the event that fuel emissions remain under the cap, this provision will help facilitate cost pass-through, reducing the risk of refinery stranded costs and providing a more consistent carbon price signal for consumers. If it is determined necessary to include emissions from the consumer use of transportation fuels in the cap and trade system, the program should be designed to:

- Create a clear carbon price signal for consumers;
- Reduce obligated party exposure to allowance price volatility with respect to the consumer compliance obligation; and
- Help companies manage working capital requirements associated with the consumer emissions compliance obligation.

ConocoPhillips has considered various options for managing transportation fuel emissions in a cap and trade program. We believe the program elements of a fixed price allowance outlined below could address some of the identified concerns:

- The State would set aside the volume of allowances necessary to cover transportation consumer emissions from use of gasoline and diesel fuel.
- The State would establish a set price for those allowances based on some average of recent allowance market prices. That price would be adjusted periodically;
- Only obligated fuel providers could purchase the set-aside allowances at the established price noted above. (CONOCO)

Comment: Transportation fuels are proposed to be subject to the Cap and Trade beginning in 2015. The current proposal has no provisions for free allowances to cover transportation fuels and thus we expect an additional penalty in excess of $350 million, increasing each year, based on the floor price of carbon. The expenditures contemplated by this draft regulation are so significant that they cannot be absorbed by industry and remain viable. If industry cannot include the cost of doing business in the price the consumer pays for its product, industry will fail or choose another venue in which to conduct business. Valero recommends that ARB provide free allowances to cover transportation fuels. Over 90 percent of the allowance costs associated with this regulation will be to cover transportation fuels in 2015. This approach is not transparent to businesses or consumers. To facilitate a more efficient allocation of company resources, allowances should be freely distributed to cover the vast majority of fuels, reducing annually at 1 percent or less (1 percent is approximately an additional $3.6 million annually, based on the floor price). This change will bring the costs associated with the Cap and Trade regulation more in-line with the expected reductions and minimize the economic impact to businesses and consumers. (VALERO)

Comment: The issue of how transportation fuel emissions might be included in the State cap and trade program is critical to the ability of in-state refiners to continue to provide adequate, reliable and affordable supplies of fuel to California consumers. ARB should develop a process to work with the California refining industry to evaluate all aspects, impacts and policy interactions of the treatment of transportation fuels in the AB 32 program. WSPA recommends that fuels not be placed under the cap until: i) an additional study of the impacts and alternatives are completed; and ii) there are widespread cap and trade programs that include fuels throughout the US and the world. (WSPA1)

> **Response:** We will continue to evaluate the treatment of transportation fuels in the cap-and-trade program, including the effects of allowance distribution to different sectors within the transportation sector, and propose any necessary changes to the regulation before the start of the second compliance period in 2015. We note the importance of transparent price signals for fuel consumers in achieving reductions in this sector.

Universities

C-14. (multiple comments)
Comment: The University believes that there is no supportable basis for allocating free allowances to industrial facilities, such as heavy manufacturing, while not also allocating free allowances to the University and other public entities which operate sources covered by the regulations. The draft cap and trade rule provides two distinct rationales for allocating allowances to industrial sector facilities: transition assistance, and leakage prevention. CARB intends to provide transition assistance to industrial facilities to prevent "sudden or undue short-term economic impacts" during the cap and trade program's initial compliance periods. The University agrees with CARB's rationale for transition assistance, but is concerned that under the proposed regulation, transition assistance will not be extended to public agencies that are regulated within the industrial sector. These public agencies, including University of California campuses and medical centers, and California State University campuses, are no less subject to severe financial impacts during initial compliance periods than are other facilities that are regulated in the industrial sector. The University therefore advocates making the following additions in the high leakage risk category of Table 8-1, "Industry Assistance": Colleges and universities (NAICS 611310), and Hospitals (NAICS 622110). These institutions should receive an allocation of allowances for transition assistance according to the Thermal Energy Based Allocation Methodology described in section 95891, "Allocation for Industry Assistance," subsection C. (UC1)

Comment: The cost to comply with the program by purchasing allowances would of course come out of general funds and would have to either come out of tuition and fees or state funding, which is unlikely given the dire strait of budget situation. So we ask for transition assistance. (UC2)

> **Response:** We disagree that the universities require free allocation. The universities are not facing a leakage risk. However, we are committed to continuing to evaluate whether the costs imposed on public entities are preventing greenhouse gas reduction opportunities from being realized due to capital constraints. One possible option under consideration is to recommend to the Legislature that auction proceeds be provided for transition assistance.

Other

C-15. Comment: Transition assistance is needed for public agencies regulated within the industrial sector. The Cap and Trade regulation provides two rationales for allocating allowances to industrial sector facilities: transition assistance and leakage prevention. According to the Initial Statement of Reasons, CARB intends to provide transition assistance to industrial facilities to prevent "sudden or undue short-term economic impacts" during the Cap and Trade Program's initial compliance periods. The District agrees with CARB's rationale for transition assistance, but is concerned that under the proposed regulation Order, transition assistance will not be extended to public agencies regulated under the industrial sector. Public agencies, including the District, are no less subject to severe financial impacts during the initial compliance periods than are other facilities regulated in the industrial sector.

Therefore, we feel that public agencies that fall within the industrial sector should be eligible for industry assistance, in the form of free allowances, and be included in Table 8-1: Industry Assistance, page A-76 of the proposed regulations. Alternatively, another approach that would be workable for public agencies is for CARB to provide public agencies, regulated in the industrial sector, the opportunity to achieve AB 32 compliance by purchasing GHG offsets to cover only those emissions over the industrial cap level. This incremental approach would be less shocking to public agency operating budgets. (CCCSD)

> **Response:** The regulation was modified to clarify that Table 8-1 applies to activities rather than to NAICS codes. Public agencies that undertake any of the activities identified in Table 8-1 are eligible for free allocation.

C-16. Comment: Simply assign the distribution utilities, at least the investor-owned ones, Auction Revenue Rights (ARRs) than go through the ritual of formally allocating the allowances to the utilities, then having them formally consign them back for auction. Similarly, we believe it would be better to assign ARRs to trade-exposed businesses, rather than actually give them allowances. (MSCG2)

> **Response:** We do not agree that Auction Revenue Rights are preferable to the consignment auction requirement for Investor Owned Utilities (IOUs) as

proposed. We believe the current framework highlights total allowance value given to the utilities and the need to use this value for the benefit of ratepayers in a way that is consistent with the goals of AB 32. As described in Appendix J of the Staff Report, distribution of utility proceeds from the sale of allowances at auction will be subject to limitations imposed by either the California Public Utilities Commission (CPUC) or by the governing bodies of publicly owned utilities (POUs). Additionally, the revenue stream generated from the sale of allowances at auction or through free allocation and use for compliance will be accounted for along with all other revenues and costs in the ratemaking actions of the CPUC and the governing bodies of the POUs. While allocation of ARRs to trade-exposed businesses might increase transparency about the amount of value embodied in leakage minimization and prevention of transition risk, ARRs would add administrative burden and would subject the recipient businesses to allowance price risk when compared to free allocation. We declined to take this approach, and instead relied on direct allocation to trade-exposed businesses for leakage prevention and transition assistance.

Free Allocation Methodology

Miscellaneous

C-17. Comment: The Kaswan PDR comments are incorporated here by reference. Of the seven options included in the original memo, I would suggest focusing on the following four options (options that could be used individually or in combination): (3) Create incentives for greater reductions in heavily-polluted areas (through differentiated allowance allocation, fees, higher allowance prices, or enhanced allowance retirement requirements. (USFLAW)

Response: We disagree with the recommendation to have different rules for facilities in different types of communities. Our analysis of the potential for localized air quality impacts indicates that there is very little chance of increased co-pollutant emissions in communities. We will monitor the implementation of the cap-and-trade regulation through an adaptive management process to identify and address any unanticipated impacts, especially localized impacts on communities, and will develop and implement appropriate responses to rectify them, including considerations of the approaches the commenter suggested here, in a public process. We agree that proceeds from the direct auction of allowances provide an opportunity for the most impacted and disadvantaged communities in California. Board Resolution 10-42 directs the Executive Officer to deposit a minimum of 10 percent of annual proceeds generated from the direct auction of allowances in the Air Pollution Control Fund for appropriation by the Legislature to programs and projects that reduce greenhouse gas emissions or mitigate direct health impacts of climate change and promote green collar employment opportunities in the most impacted and disadvantaged communities in California.

Adjustment upon Linkage

C-18. Comment: Table 6-1 in section 95841 (p. A-60) sets out California GHG Allowances Budgets for each year of the cap and trade program. The ISOR states: "Each time California links to a WCI partner jurisdiction from which California imports electricity, staff will need to reevaluate these annual budgets." This important statement should be reflected in the regulation itself, either in section 95841 or in subarticle 12 on linkage to external greenhouse gas emissions trading systems. If the amounts of freely allocated allowances may also change due to linking, this should also be mentioned in the regulation. (SCPPA1)

> **Response:** We do not agree with the commenter's proposal to include the statement, "Each time California links to a WCI partner jurisdiction from which California imports electricity, staff will need to reevaluate these annual budgets," in section 95841 or subarticle 12 of the cap-and-trade regulation. A linkage to a partner jurisdiction would require a separate regulatory action. We cannot currently anticipate all potential regulatory text changes that would be required under such a rulemaking. The impact on annual budgets is an example of a potential regulatory change that would be evaluated during such a rulemaking.

Recovery of Allowances – Lien Mechanism

C-19. Comment: CCAP recommends the cap and trade regulation include a lien mechanism, at least with respect to any allowances distributed through free allocation, to allow ARB to recover outstanding allowances to protect the integrity of the cap and trade program. (CCAP1)

> **Response:** We disagree with the commenter's suggestion. We do not believe a lien mechanism should be included in the cap-and-trade regulation in order to recover outstanding allowances. We believe the commenter's concern is addressed by the allowance allocation approach we have developed. Specifically, the updating nature of industrial allocations under the product-based allocation approach should address concerns about over-allocation of allowances to individual industrial facilities.

New Entrants

C-20. Comment: CLFP recommends that new processes and plant expansions added to existing facilities should be regarded as new entrants into the program and provided free allocations. (CALFP1)

> **Response:** Our preferred approach to treatment of expansion at incumbent facilities is to address this issue using updating product-based allowance allocation.

Shutdown of Facilities

C-21. (multiple comments)
Comment: Provide for the ability to use allowances and credits that result from shutdowns or curtailments. The regulation and supporting documents indicate that facilities may not retain nor gain allowances if they cease operations. This could be a logical provision. Depriving sources of the ability to gain revenue from the shutdown of emitting units will encourage older and inefficient emitting units to stay on line. Knowing that it will forfeit its allowances and credits, a source operator will be inclined to keep the source operating as long as feasible. This will have the dual effect of discouraging equipment replacement, thereby keeping inefficient sources online; and keeping credits from the market, thereby reducing supply. (CANOTRCO2E)

Comment: The proposed rule denies an allocation of allowances to facilities or businesses that shut down operations. For example, if there is a source that is relatively inefficient in using fossil fuels, it is incentivized to continue operating in order to maintain its allocation of allowances. It would either sell or use the allowances, depending on its own usage profile. An optimal profile might be to continue operating at a low level in order to obtain allowances that can be sold at a higher profit than would occur as a result of operation. (HOR)

> **Response:** We do not agree that the regulation promotes the use of inefficient units. Our industrial allocation approach is based on emissions efficiency benchmarks. Product-based benchmarking is based on emissions intensity per unit product. An inefficient unit relative to these benchmarks will be disadvantaged relative to a more efficient unit. The number of allowances received is proportional to the amount of product produced, so a facility that operates at a low level will not obtain the same level as it would at a higher level of operation.

Ability to Appeal Allocation

C-22. Comment: The regulations (Subarticle 9: Direct Allocations of California GHG Allowances) are silent on whether the allocation is appealable. (CAPCOA1, CAPCOA2)

> **Response:** The regulation does not provide for an appeal process because we do not believe there is a need for an allocation appeal process.

Order of Allocation

C-23. Comment: Section 95870 of the proposed regulation prioritizes allowance allocation in the following order: 1) Allowance Price Containment Reserve; 2) Advance Auction; 3) Allocation to Public Utilities; and 4) Allocation to Industrial Covered Entities. According to section 95870(d)(3), the total number of allowances allocated to industrial covered entities can be reduced in order to ensure that there are sufficient allowances available for the electric distribution utilities. If there are not enough allowances, then what remains will be prorated equally across all eligible covered entities. AB 32, however, requires ARB to design measures to minimize leakage to the extent feasible. Consequently, it seems unfair to favor assistance to the public utilities over industrial covered entities. A more equitable approach would be to prorate the remaining allowances between the electric distribution utilities and the industrial entities. (CACC)

Response: Our justification for allocation to electrical distribution utilities is fundamentally different from the reasons for allocation to industrial sectors. The industrial allocation approach is designed to provide transition assistance and minimize emissions leakage. The electrical utility allocation is designed to protect electricity customers and reward these customers for utility investment in renewable energy and energy efficiency. Any allowance allocated to electrical distribution utilities must be used exclusively for the benefit of retail ratepayers of each electrical distribution utility, consistent with the goals of AB 32, and may not be used for the benefit of entities or persons other than ratepayers. Industrial allocation is not subject to the same limitations. We prioritized allocation to electrical utilities because of the differences between these two allocation categories.

Pro-Rata

C-24. (multiple comments)
Comment: Section 95870(d)(3) provides that if the amount allocated to industry exceeds the amount of allowances available, then the number of allowances available will be prorated equally across "all eligible covered entities." SCE seeks clarification as to whether the pro rata cuts to allocation apply to just the industrial sector, or to all parties receiving a direct allowance allocation. (SCE1)

Comment: Under the heading "Allocation to Industrial Covered Entities," section 95870(d)(3) (p. A-75) provides for pro-rating of allowances allocated for the purposes of industrial assistance. However, there is a reference to pro-rating allowances across "all eligible covered entities." This is a broad term that could be construed to include entities in other sectors such as electrical distribution utilities. To avoid confusion, the term "all eligible covered entities" should be replaced with "all eligible industrial covered entities." (SCPPA1)

Response: We agreed and modified the previous section 95870(d)(3), now section 95870(e)(3), to read "all eligible industrial covered entities."

Opt-In Entities

C-25. Comment: Section 95813(d) (p. A-43) allows opt-in entities to receive freely allocated allowances subject to subarticles 8 and 9. This is too broad. Given that opt-in entities are highly unlikely to be electrical distribution utilities, the cross-references should be more specific and should refer to the allowance allocation provisions applying to industrial entities. Modify this section as follows:

An opt-in covered entity may be eligible to receive freely allocated allowances subject to subarticles 8 and 9 under sections 95870(d), 95890(a), and 95891. (SCPPA1)

Comment: The Utilities appreciate CARB's desire to encourage reductions in emissions from entities without compliance obligations and understand that opt-in covered entities are intended to come only from the Industrial Sector. The Utilities request further clarification of this intent. If such clarification is not provided and the opt-in provision is too broadly interpreted, opt-in covered entities from the electric sector could skew the allowance allocation for electric distribution utilities with a mandated compliance obligation, which would obviate the cost effectiveness of the cap-and-trade program. No entity would be excluded from participating in the cap-and-trade program through the changes recommend by the Utilities above because non-obligated entities that desire to participate in the emission reduction goals can participate as VAEs. Modify section 95813(a) and (d) as follows:

(a) An entity that meets the requirements of section 95811(a), but does not exceed the inclusion thresholds set forth in section 95812 (b)(1) may elect to voluntarily opt-in to the cap-and-trade program.

(d) An opt-in covered entity may be eligible to receive freely allocated allowances subject to ~~subarticles 8 and 9~~ 95891. (MID1)

> **Response:** We do not agree that section 95813(d) is too broad or that it should be modified. To become an opt-in covered entity pursuant to section 95813 the entity must meet the requirements of 95811, which defines covered entities. This section does not include electrical distribution utilities (although some electrical distribution utilities may also be covered entities because they are a first deliverer of electricity). Table 9-3 specifies which entities are eligible to receive free allowances allocated to the electricity sector in section 95870(d).

Greater Detail Required

C-26. (multiple comments)
Comment: It is noteworthy that CARB staff has failed to determine levels for allocation that we urgently need to know, yet CARB staff is willing to commit immediately to impose a massively burdensome new charge on manufacturers for unspecified and unjustified purposes in the future. In fact, by indicating now that costs will be significantly higher in future compliance periods due to the proposed auction, CARB could cause immediate economic harm and leakage as entities start preparing to reduce their California footprint to minimize costs.

While the proposed budget cap for the first year is intended to provide the California economy most of the allowances it needs to operate as usual, there will be winners and losers within each industry sector. For entities operating facilities less efficient than the benchmark, there will be immediate new obligations to purchase allowances to make up the difference between their free allowances and what is needed to operate. At this time they do not know how many allowances they will receive for free, and they don't know when they will get this crucial information. This uncertainty will exacerbate an already difficult economy and will discourage manufacturing investment and new hiring.

Because total allowances in the system is capped, a too generous allocation for one sector will operate to the detriment of others, both within and without each sector. Unless we understand all the benchmarks and allocation determinations soon, the public will not have a meaningful opportunity to comment on the total impact of all allocation decisions prior to the market opening in 2012.

For this reason, we recommend that CARB resolve to require staff to provide the Board and the public a report on the progress toward establishing benchmarks by April 30, for review by the CARB Board at the May meeting, with a target to have final determination on benchmark methodologies, procedures needed and documentation requirements no later than June 30, 2011. (CMTA1, CMTA2)

Comment: CARB has not provided adequate justification for the proposed allocation scheme. Regardless of the framework used however, EDF encourages CARB to explain their allocation assistance scheme reasoning more completely. (EDF1)

Comment: ARB has not proposed a plan of allocation for the allowances. For example, it has not stated whether allowances will be allocated on the basis of past emissions, or how the emissions baseline might be calculated. Each regulated entity has some idea of how the cap relates to overall demand, and how it might affect that entity's operations and costs. But without understanding the allocation plan, the actual impacts and costs cannot be assessed or anticipated. It is not possible to comment on the proposal because there is no proposed allocation plan, which is the heart of the proposed rule. The proposal is incomplete in fundamental ways. (HOR)

Comment: The regulation proposes that most allowances be freely allocated at least at the program's onset, primarily to assist the most leakage prone industries. Yet, the regulation lacks critical details for the allowance allocation of various industry sectors in future compliance periods. There remains uncertainty as to how allowances will be allocated to these sectors. CalChamber encourages CARB to make this critical design detail available as soon as possible so that compliance entities have certainty and can make decisions moving forward. (CALCHAMBER1)

Comment: As of today, the companies don't have their benchmarks. That's a big concern. They'd like to be able to come back if you have that within the 15 days and be able to comment again. (INDENVASSOC)

> **Response:** We have finalized the allowance allocation system as directed by Board Resolution 10-42, including benchmarks for allocation to industrial sectors. Please see Appendix B to the first 15-day change to the regulation for an explanation of the development of product benchmarks for allowance allocation,

and Table 9-1 in Section 95891 of the regulation for the updated product-based emission efficiency benchmarks.

Third-Party Reductions / Disadvantaged Communities

C-27. Comment: Carve out allowances from the cap to credit verified third-party reductions achieved in disadvantaged communities. While the AB 32 Scoping Plan notes the important roles to be played by all communities of California, the current proposal has only weak links between the cap-and-trade program and the communities that are currently at risk from a variety of environmental health risks, and that also face the greatest risks of climate change. These same communities are poised to be a part of the solution, and that solution may include a variety of measures including household and commercial building energy efficiency investments, regional transportation and land use planning, agricultural conservation strategies, and urban forestry. Some system for incentivizing reductions from third party community benefits organizations, land managers and municipalities should to be built into the program to leverage the important opportunity to engage and reward investments that benefit California's disadvantaged communities.

EDF continues to support the idea of setting aside allowances to credit actions by third parties that demonstrate verified emissions reductions. CARB need only embrace protocol development for community-based, within-capped-sector reductions achieved by third parties, and set aside allowances to credit such reductions once they are verified. Because these credits would be given for emissions reductions that are achieved in capped sectors, we emphasize that such a program must be funded by allowances taken from under the cap, rather than using allowances that are "on top of" the cap. (EDF1)

Response: While we encourage such GHG-reducing measures as those listed above, we did not directly allocate allowances to incentivize these actions. We believe the cap-and-trade program will encourage these actions through either price signals due to coverage of the capped sectors or through our compliance offsets program. Additional AB 32-related programs such as SB 375 and existing energy-efficiency programs will also help motivate these actions. Auction proceeds could potentially be an appropriate source of funding for some of these activities.

We agree that proceeds from the direct auction of allowances provide an opportunity for the most impacted and disadvantaged communities in California. Board Resolution 10-42 directs the Executive Officer to deposit a minimum of 10 percent of annual proceeds generated from the direct auction of allowances in the Air Pollution Control Fund for appropriation by the Legislature to programs and projects that reduce greenhouse gas emissions or mitigate direct health impacts of climate change and promote green collar employment opportunities in the most impacted and disadvantaged communities in California.

Disadvantaged Communities

C-28. (multiple comments)
Comment: We urge CARB to include provisions in the regulation to set aside a minimum four percent of allowances from the industrial and electricity sector from the outset of the program to be made available through auction and dedicate the revenue to the Community Benefits Fund. Funds should be used for programs or projects in the most impacted and disadvantaged communities identified by CARB to air pollution and climate change mitigation measures (i.e., home energy efficiency investments, pollution control measures, smart growth land use planning), community public health programs (i.e. mitigating health impacts of climate change, community health improvement, public health preparedness), and to promote green collar employment opportunities in these communities (i.e. investment in worker transition programs). We recognize that the Legislature must direct the specific uses of funds collected under the cap and trade program, but we believe that CARB must establish the important precedent of setting aside funds for protection of the most vulnerable communities. (KUSTIN11, KUSTIN12)

Comment: CCAP joins other organizations here in urging that specific language be included in the rule's reference the work of the Economic Allocation Advisory Committee and specific recommended uses for allowance value, including investments in infrastructure to support smart growth as well as adaptation work to ensure health urban communities and protection of our natural resources. (CCAP2)

Comment: Include provisions in the regulation to initiate a Community Benefits Fund (CBF) from the outset of the Cap and Trade Program. Set aside a minimum 4 percent of allowances from the industrial and electricity sector from the outset of the program to be made available through auction and dedicate the revenue to the Community Benefits Fund. Funds should be used for programs or projects in the most impacted and disadvantaged communities identified by CARB to:

- Air pollution and climate change mitigation measures. (i.e., home energy efficiency investments, pollution control measures, smart growth land use planning)
- Community public health programs (i.e. mitigating health impacts of climate change, community health improvement, public health preparedness)
- Promote green collar employment opportunities in these communities. (i.e. investment in worker transition programs) (KUSTIN02, SIERRACLUBCA4)

Comment: We urge CARB to carve out allowances from the outset of the program to be used for a Community Benefits Fund (CBF). Inclusion of a community investment program has been broadly supported by community-based, environmental justice, health, and environmental organizations throughout the development of the Cap and Trade program. AB 32 requires CARB to “direct public and private investment toward the most disadvantaged communities in California.” While the CBF is noted in the staff report as a possible use of allowance value, there is not a specific recommendation to create and operate a fund by a certain date. We urge CARB to include provisions in the regulation to set aside a minimum of 4 percent of allowances from the industrial and

electricity sector from the outset of the program, and from the transportation and natural gas sectors when they are included in the program in 2015, and dedicate the revenue to the CBF. We recognize that the Legislature has ultimate authority over the use of funds collected under the program, but we believe that CARB should include a carve out in the regulations for the creation of a CBF, and a recommendation to the legislature that these funds be used to protect and benefit our most vulnerable communities.
CARB should recommend that funds be used for programs or projects in the most impacted and disadvantaged communities CARB has identified to:

- Reduce GHG emissions (i.e., home energy efficiency investments).
- Mitigate public health impacts of air pollution and climate change (i.e., pollution reduction strategies, public health programs).
- Promote green collar employment opportunities within these communities (i.e., investment in worker transition programs). (KUSTIN10, EBERHARD)

Comment: ARB should clearly define how the Community Benefits Fund would be used. We recommend that ARB set aside at least four percent of allowances from industrial and electricity sectors for use by the most impacted and disadvantaged communities for public health protections. We note that AB 1405 (deLeon) called for setting aside 10 percent of allowances. Community benefit funds should target programs and projects for air pollution and climate change mitigation measures, community public health programs, and local green collar employment opportunities. (CATHCHAR1, CIPAL)

> **Response:** Per Board Resolution 10-42, ARB will deposit a minimum of 10 percent of annual proceeds generated from the direct auction of allowances in the Air Pollution Control fund for appropriation by the Legislature for programs and projects that reduce GHG emissions or mitigate direct health impacts of climate change, and promote green collar employment opportunities in the most impacted and disadvantaged communities in California. Although we cannot mandate how these funds will be spent, we believe this demonstrates the Board's support for achieving the goals outlined in the comments above. Per Board direction, we are developing recommendations to the Legislature and the Governor on the use of these funds.

EU ETS

C-29. Comment: The world's largest cap and trade scheme is the European Union Emissions Trading Scheme (EU ETS). In the first phase of the scheme, from 2005-2008, however, far too many emissions permits were handed out to these industries—largely as a result of intensive corporate lobbying—a practice that will almost certainly take place in California too.

The fundamental problem of "overallocation" and avoiding necessary domestic action remains too. The EU's figures for 2008 show an overall reduction in emissions of around 50 million tonnes, but these figures were inflated by over 80 million tonnes of credits from carbon offsets, mainly from the Clean Development Mechanism (CDM) which gives credits for “emissions-saving projects” in developing countries (for more on the problems with this see below). In other words, more than the entire claimed “reduction’” was generated by projects outside of Europe.

With a further surplus of permits, another price collapse in the EU ETS followed. Allocations for the second phase of the scheme were made on the assumption that European economies would keep growing. The recession has reduced output and power consumption, leaving companies with a surplus of permits. This is already storing up problems for the third phase of the EU ETS too. The main reason why the price of EUA permits in phase 2 has not collapsed to zero is that it is now possible to “bank” them—in other words, to hold onto them for use in the third phase of the scheme, which will run from 2013 to 2020.

Surplus allowances will dog carbon market. The World Bank estimates a surplus of 970 Mt CO_2e (million tonnes) by the end of phase 2. This would account for almost 40 per cent of the “reduction” that the EU claims will be required of power companies and industries covered by the ETS in phase 3 of the scheme. This figure might yet be higher if companies decide to purchase a significant number of offset credits and “bank” these too. The net result of this could be that the EU ETS will require very few domestic emissions reductions before 2020, and quite possibly none at all. (CTW)

> **Response:** We do not agree that California’s cap-and-trade program will over-allocate allowances. We studied the strengths and weaknesses of all existing cap-and-trade programs, including the EU-ETS and learned from these systems in developing our program to avoid over- or under-allocating allowances. We determined that a soft start, under the current economic conditions, dictates greater reliance on free allocation of allowances in the early years of the program. We view this free allocation as critical to avoid, adding an immediate cost to covered industries that could inhibit their ability to invest in emissions reductions. Unlike the first phase of the EU ETS, the free allocation proposed in California relies on ambitious emissions intensity benchmarks developed using reported actual emissions, minimizing the potential for over-allocation. As the program progresses, we propose a transition to a heavier reliance on auctions for allowance distribution while still minimizing leakage where risk exists.
>
> The commenter notes that allocations for the second phase of the EU ETS were made on the assumption that European economies would keep growing, leading to a surplus of permits because of the recession. In this regulation, free allocations will be based on future actual reported production data, not assumptions. The allocations will be “trued-up” so production data years match the emission data years. This mechanism will prevent over-allocation of allowances due to overestimates of economic growth.
>
> The commenter further notes that reductions in the EU ETS were “inflated” by credits from CDM offset projects. ARB recognizes that some CDM credits created during this period may have been non-additional. ARB does not

currently plan to accept CDM credits until these issues in that system are resolved. Furthermore, all future offset protocols will need to be approved by the Board after a public process. In this regulation, offsets must be generated in accordance with strict protocols adopted by the Board and are limited to eight percent of each entity's compliance obligation.

In addition, we are committed to monitor the implementation of our program and make adjustments as necessary.

Allocation Based on Production Only

C-30. Comment: CARB staff proposes free allocation of allowances for all industrial sectors for the first compliance period, but not for the second and third periods. We recommend the free allowance distribution up to the output-based benchmark for each sector in all compliance periods up to 2020. (CMTA1)

Response: We do not agree. We are allocating free allowances to industrial sectors for as long as their leakage risks remain for the second and third compliance periods. See also responses to Comments C-2 or C-31.

Auction Preferred, Avoids Over-Allocation

C-31. Comment: Under an auction system, the market (rather than the state) chooses the winners. Those who can adjust their operations in a fashion that results in fewer emissions and those who elect to purchase allowances determine which solutions advance. This is preferable to the situation where a team of well-meaning government officials have a windfall of monies to spend on solutions that are unfunded by the market. There are a number of instances where the European experience of 'windfall profits' in the EU Emissions Trading Scheme (EU ETS), illustrates why free-allocation should be avoided. In Europe, there was a small amount of over-allocation to particular industrial sectors in a small number of Member States. This was because some individual Member States were using the EU ETS as a way of providing indirect subsidies to local industry, to better enable them to compete with industry in other Member States. The European Commission caught most of these and slashed their allocations, but some slipped through. Windfall profits from over-allocation were not material however. The material windfall profits were made in the electricity industry, the industrial sector which was universally under-allocated across Europe. On average, European electricity generators received free allocations amounting to around 85 percent of their needs and had to buy the remaining 15 percent on the market. Consequently, they raised all of their electricity prices by 100 percent of the marginal purchase cost of the allowances acquired. They used emissions trading as an excuse to increase prices by more than costs, and thus secure windfall profits. This occurrence is the clearest demonstration that competition in the European electricity sector is not as fierce as the generators would have you believe. Thus, windfall profits in the electricity sector are an issue for electricity regulation, not emissions trading. It is important to note that the ability to increase prices by more than costs is a function of regulation and competition, and independent of whether allowances are auctioned or allocated. (CANTORCO2E)

> **Response:** We agree that auction is the fairest and most transparent means of distributing allowances. The cap-and-trade regulation is designed to gradually transition from mostly free allowance distribution to a system in which most allowances are auctioned. This transition provides regulated sources time to get used to the market and the need to procure allowances. This approach gradually introduces a carbon price on goods that consumers purchase while simultaneously ensuring that emission reductions occur. We recognize that the long-term success of the program will require significant investment in emissions reductions. However, under current economic conditions, an early emphasis on auction could hamper the ability of California sources to invest in low-carbon technologies. Further, freely allocating allowances in the early years of the program will help prevent leakage. Allocating the allowances for free using emissions-efficiency benchmarks will reward companies that have already made investments in energy-efficiency and carbon reductions, and will not penalize those that produce goods in California. The overall allocation approach includes: creation of an Allowance Price Containment Reserve for cost-containment purposes, a Voluntary Renewable Electricity reserve, free allocation to the industrial sector for transition assistance and leakage prevention, free allocation to electrical distribution utilities on behalf of ratepayers, and auction of the remaining allowances.

Oppose Free Allocation

Maximize Auctioning, Minimize Allocation

C-32. Comment: We recommend the maximum use of auctioning as the method of allocating allowances, subject to a short initial period of adjustment. (UCS3)

> **Response:** We agree that auction is the fairest and most transparent means of distributing allowances. We recognize that the long-term success of the program will require significant investment in emissions reductions. However, under current economic conditions, an early emphasis on auction could hamper the ability of California sources to invest in low-carbon technologies. Further, freely allocating allowances in the early years of the program will help prevent leakage. Allocating the allowances for free using emissions-efficiency benchmarks will reward companies that have already made investments in energy efficiency and carbon reductions, and will not penalize those that produce goods in California.

Higher than Needed for Leakage

C-33. (multiple comments)
Comment: The Advanced Technology Development report notes that subsidizing GHG intensive products through GHG allowance allocations can create a barrier to this

transition (see page 1-10). The Economic and Allocations Advisory Committee found that the need for free allowances to address leakage is small.

We believe that the proposed regulation relies too heavily on giving producers such as refineries and oil productions free allowances based on the amount of petroleum they produce or refine (i.e., the higher the level of production, the higher the level of subsidy) as discussed further below. We recommend focusing more on assistance to both producers and end-users who take action to help meet California's ambitious GHG goals and provide associated environmental and economic benefits. We believe that cleaner and more efficient vehicles, fuels, and transportation systems are important examples of these opportunities. (ICCT1)

Comment: While I agree with many of the steps outlined in the AB 32 Scoping Plan, I am concerned by the over-allowance of free pollution credits to the industrial sector in the Cap and Trade design. I urge you to revisit, revise, and phase out free allocation to the industrial sector. The proposed level of free allocation to the industrial sector is likely much higher than is needed to combat leakage. (TAYLORE)

Comment: We urge ARB to heed the advice of EAAC, who recommended that ARB rely on auctioning as the method for distributing allowances. While we appreciate the worry that auctioning might encourage industries to leave the state, we note that ETAAC recommended that allowances be limited to no more than 15 percent. According to ETAAC, this would more than adequately compensate energy intensive industries for potential leakage. (CATHCHAR1)

Comment: I urge you to revisit, revise, and phase out free allocation to the industrial sector. The proposed level of free allocation to the industrial sector is likely higher than is needed to combat leakage. Several research studies have found that the "leakage" claims of the industrial sector are exaggerated and subsidizing these industries through free allowances creates barriers to transitioning to a cleaner economy. CARB should build in an explicit adaptive management process to adjust the free allocation to the industrial sector based on specified evaluation metrics. Please take advantage of the favorable public climate that California currently enjoys around addressing climate change and implementing AB 32 by taking much-needed bold actions and removing the massive allowance giveaways outlined in the current rules. (MOYNAHAN, CLCV)

Comment: The proposed level of free allocation to the industrial sector is likely much higher than is needed to combat leakage and should be revisited and revised.
All stakeholders agree that we must prevent leakage of industrial jobs out of California. However, excessive allocation beyond what is needed to avoid leakage is akin to subsidizing GHG-intensive products and services, a consequence counter to our need to transition to cleaner and efficient alternatives. The proposed allowance allocation in the industrial sector will concentrate resources primarily among large oil, cement, and chemical companies instead of providing transition assistance to a broad range of small and large businesses.

We believe that CARB has been overly generous in giving more allowances than are actually needed to prevent leakage. The proposed free allocation to the industrial sector is worth billions of dollars. Any portion of that amount that is not necessary to maintain competitiveness and prevent leakage will be pocketed by the industry while the price of carbon is passed on to their customers, resulting in a windfall profit to the industry. CARB must strive to ensure that any free allocation is absolutely necessary to maintain competitiveness, prevent leakage, and does not result in any windfall profit.

Although there is little information available specifically on the competitiveness concerns of California industries, there is research to suggest that a much smaller portion of allowances would sufficiently protect against leakage. For example, a newly available report from UCLA Professor Matthew Kahn and Erin Mansur of Dartmouth College, *How Do Energy Prices, and Labor and Environmental Regulations Affect Local Manufacturing Employment Dynamics?*, finds that leakage claims of industrial sector firms are overblown: “Energy prices are only a significant determinant of locational choice for a handful of manufacturing industries such as primary metals” (p. 24). Empirical evidence from the EU ETS also suggests that leakage will not be a significant problem large enough to warrant long-term giveaways that eventually act more as crutches than investments. ETAAC also recognized that subsidizing GHG-intensive processes and products through free allowance allocation creates barriers to transitioning to a cleaner, more efficient economy. (KUSTIN10, EBERHARD)

Comment: 100 percent free allocation to first tier industrial emitters is excessive. Another option would be to tax the resulting windfall profits so that a portion of that allowance value is recaptured and can be used for public purposes. Industry-specific benchmarks encourage manufacturers using current technologies to add some moderate efficiencies to their processes, but may disadvantage out-of-the-box innovators that produce carbon negative cement products (for example, Calera, Inc.) and shield current technologies which would otherwise become less economical due to the carbon price. We urge CARB to reduce the free allocations to the minimum amount suggested by the EAAC. (CPC1)

Comment: Commit to maximize the use of auctioning as a method of allocating allowances. The value of allowances CARB proposes to freely distribute to the industrial sector amounts to billions of dollars and will far exceed the amount needed to address potential emissions leakage from trade-exposed industries. The economic “dream team” that was assembled to advise CARB on cap and trade design, the Economic and Allocation Advisory Committee, stated in its report that “relatively little allowance value would be needed under this mechanism to address leakage.” Many economic research reports from the US and Europe suggest that leakage risks can be accounted for through less than 20 percent free allocation. For example, Resources for the Future calculates that “only about 15-20 percent of allowances are needed to compensate energy-intensive industries, for their loss of producer surplus, so the huge bulk of allowances could still be auctioned.” Stanford’s Professor Larry Goulder and colleagues find that “under a wide range of cap and trade designs, freely allocating less than 15 percent of the total allowances prevents profit losses to these most vulnerable industries. Allocating 100 percent of the allowances substantially overcompensates these industries, in many cases causing more than a doubling of profits." UCLA Professor Matthew Kahn and Erin Mansur from Dartmouth College find that "energy prices are only a significant determinant of locational choice for a handful of manufacturing industries such as primary metals." This provides further evidence that 100 percent free allocation is excessive. (UCS1, WALTERS, LUDLOW)

Comment: We urge ARB to pay close attention to the recommendations of its own Economic and Allocation Advisory Committee (EAAC). The EAAC recommended that ARB rely on auctioning as the method for distributing allowances, and was against supporting industry profits with allowance value, except when it is a byproduct of efforts to prevent potential leakage. Both EAAC and the Economic and Technology Advancement Advisory Committee of the Air Resources Board found that 10 to 15 percent of allowances would more than adequately compensate energy intensive industries for potential leakage. (CIPAL)

Comment: While we understand that the industrial sector has some uncertainty with respect to trade exposure and potential leakage, we believe that the current regulatory proposal to freely allocate the majority of allowances to the industrial sector through 2020 without a clear process for potentially increasing the auction of allowances could result in an excessive amount of free allowances needed to address leakage and delay progress toward more efficient technologies. (NC1)

Comment: TNC recommends language that would facilitate greater auction of allowances for the industrial sector over time. We believe that the current regulatory proposal to freely allocate the majority of allowances to the industrial sector through 2020 without a clear process for potentially increasing the auction of allowances could result in an excessive amount of free allowances needed to address leakage and delay progress toward more efficient technologies.

As advised by the Economic and Allocation Advisory Committee (EAAC), the industrial sector should need very little allowance value to address leakage issues. We, therefore, urge CARB to amend its regulations to create benchmarks and a process to facilitate a greater amount of auctioned allowances in the industrial sector over time to ensure that this sector has the proper incentives to transition to more efficient technologies and reduce GHG emissions by 2020. (NC2)

Comment: We recognize the need to address leakage risk for trade-exposed industries and strongly support transitional assistance in the form of some percentage of allocations being distributed for free. The goal is to assist and to provide compensation to bring California production facilities to cost parity with competing facilities in non-capped areas. This can be accomplished with a relatively small percentage of the total allowance value. One hundred percent seems excessive and risks overcompensation. We urge staff to evaluate and reassess the impact of free allocation. (UCS4)

Comment: The proposed level of allocation to the industrial sector is much higher than is needed to combat leakage. Your own Economic and Allocations Advisory Committee found that the need for free allowances to address leakage is small. The biggest recipients of these free allowances in the staff proposal are the oil extraction and refining industries, which actually have a low susceptibility to leakage. We ask you to re-classify petroleum extraction and refining as low leakage risks, and to reduce their free allocations accordingly. (SIERRACLUBCA4)

Comment: We are concerned that the assistance factors in the proposed regulation are overly generous and will devote allowance value to industry profits at the expense of consumer welfare. Studies at the U.S. and EU level indicate that only about 10-20 percent of free allowances are needed to prevent leakage. While California-specific data is required to determine the competitiveness concerns of the program, CARB should ratchet down free allowances in the industrial sector should the data show that the allocation formula is overcompensating for leakage risk. (NRDC1)

Comment: Preventing leakage is an important policy objective, particularly given current economic conditions. However, the provisions in the regulation do not appear to be warranted by the available evidence on the likelihood of emissions leakage as a result of AB 32, or the magnitude of allowance allocations necessary to ameliorate it. Drawing on a review of the scholarly literature, the CARB-convened Economic and Allocation Advisory Committee (EAAC) concludes that—addressing leakage through free allocation would require a very small share of allowance value. Despite this finding, CARB proposes an allocation scheme that may use generous benchmarks and fail to phase out the free allocation over time for the vast majority of covered industrial emissions. Instead, CARB proposes using a constant assistance factor of 100 percent for significant portions of industrial emissions. (EDF1)

Comment: In general, the provisions for specific industries, including cement and the petroleum extraction and refining, appear to be more generous than needed if the purpose of the allocation is to avoid creating an incentive for these businesses to leave the state. (EDF1)

Comment: We recognize the need to address leakage risk for trade-exposed industries and strongly support transitional assistance in the form of some percentage of allocations being distributed for free. The goal is to assist and to provide compensation to bring California production facilities to cost parity with competing facilities in non-capped areas. This can be accomplished with a relatively small percentage of the total allowance value. One hundred percent seems excessive and risks overcompensation. We urge staff to evaluate and reassess the impact of free allocation. (UCS4)

> **Response**: We agree that auction is the fairest and most transparent way to distribute allowances. We are allocating allowances to the industrial sector for two purposes: (1) to provide transition assistance, and (2) to prevent leakage. Transition assistance provides free allocation to the industrial sector at the outset

of the program to avoid sudden or undue short-term economic impacts and promote a transition to a low-carbon economy. This transition assistance will decline as covered entities gradually adjust to the carbon price and adopt energy- and carbon-saving strategies. The regulation does not provide 100 percent free allocation to industrial emitters.

Free allocations will decline over time based on two main factors. One is the "cap decline" factor, which is what ensures that we will reduce emissions to meet the 2020 goal. The cap declines at 2 percent each year for the first compliance period, and then at 3 percent a year from 2015 through 2020. The second factor is based on the risk of emissions leakage. We have conducted an extensive analysis of leakage risk with a peer-reviewed methodology used in existing cap-and-trade programs. This methodology combines two considerations: trade exposure, and the degree to which greenhouse gas emissions influence the cost of the end product. The methodology is described in greater detail in the Staff Report and Appendix K of the Staff Report. Sectors that have high leakage risk will continue to receive a high percentage of allowances for free through 2020. Sectors with medium or low leakage risk will see reductions in their free allocations beginning with the second compliance period in 2015. These percentages of free allowances are detailed in the regulation. Per direction in Board Resolution 10-42, we are committed to revisit the leakage analysis before 2015, and to adjust leakage risk as necessary to reflect the results of the revisited analysis.

We do not agree that the proposed regulation over-allocates free allowances to prevent leakage. AB 32 directs the Air Resources Board to design all GHG regulations to minimize leakage to the extent feasible. The California cap-and-trade program was designed to not unduly disadvantage California industry. Introducing an environmental regulation in one jurisdiction can cause production cost and prices in that jurisdiction to increase relative to costs in jurisdictions that do not introduce comparable regulations. This can precipitate a shift in demand away from goods produced in the implementing jurisdiction toward goods produced elsewhere. As a result, the reduction in production and emissions in the implementing jurisdiction is offset by increased production and emissions elsewhere.

Too Many Free Allowances

C-34. (multiple comments)
Comment: We are disappointed by the amount of free allowances given to the industrial sector emitters, and by the delayed move towards auctioning. We urge CARB to ensure 100 percent of permits are auctioned. (CPC1)

Comment: In the industrial sector, the free allocations are excessive and should be reduced. (FORMLETTER01, FRIEDENBERG, HANSON, KUNKEL, SONOMAFCC)

Comment: In the industrial sector, the free allocations are excessive and should be reduced. Free allocations based on industry-specific benchmarks encourage some moderate efficiencies, but may disadvantage innovators (for example, a new company that produces carbon negative cement products). How many free allowances would a start-up get in relation to an incumbent cement factory? Free allocations may prevent "leakage" of the old technology by shielding business-as-usual from the carbon price. (CARBONSHARE)

> **Response:** We do not believe that the proposed regulation over-allocates free allowances to the industrial sectors. At the beginning of the program, most allowances are distributed for free to help provide a soft start for the program. Industry assistance is necessary to provide a smooth transition into the cap-and-trade program for industrial covered sources that face a competitiveness risk. The level of assistance allocated will decline over time to a minimum level necessary to prevent emissions leakage as industrial sources adapt to carbon constraints. The allocation system is also designed to reward those who have taken early action and have invested in energy efficiency and GHG emission reductions, and it will encourage continued investment in efficiency and clean energy in the future.
>
> In response to the CarbonShare, a new entrant would be allocated according to its industry. A start-up cement factory would be allocated according to its production, similar to other existing cement facilities.

C-35. Comment: As advised by the Economic and Allocation Advisory Committee (EAAC), the industrial sector should need very little allowance value to address leakage issues. We, therefore, urge CARB to amend its regulations to create benchmarks and a process to facilitate a greater amount of auctioned allowances in the industrial sector over time to ensure that this sector has the proper incentives to transition to more efficient technologies and reduce GHG emissions by 2020 (NC1)

> **Response:** We agree that auction is the fairest and most transparent way to distribute allowances. We do not agree that the proposed regulation over-allocates free allowances to the industrial sector. At the beginning of the program, most allowances will be distributed for free to help provide a soft start for the program. The allocation system is designed to reward those who have taken early action and have invested in energy efficiency and GHG emission reductions, and it will encourage continued investment in efficiency and clean energy in the future. Our program is designed to transition into more heavy reliance on auctions beyond the initial period. Per Board Resolution 10-42, we added product benchmarks to the regulation.
>
> Free allocations will decline over time based on two main factors. One is the "cap decline" factor, which ensures that we will reduce emissions to meet the 2020 goal. The cap declines at 2 percent each year for the first compliance period, and then at 3 percent a year from 2015 through 2020. The second factor

is based on the risk of emissions leakage. Staff has conducted an extensive analysis of leakage risk with a peer-reviewed methodology used in existing cap-and-trade programs. This methodology combines two considerations: trade exposure, and the degree to which greenhouse gas emissions influence the cost of the end product.

C-36. Comment: Industrial sources should not benefit from free allocations. ARB has proposed to freely allocate allowances to industry at the outset of the program and on an on-going basis potentially lasting the entirety of the program. This amounts to an effective delay in emissions reduction and a missed opportunity for Valley communities, contrary to the specific intent of AB 32. By freely allocating allowances, ARB denies low-income, industrial-hosting, communities much needed revenue and the opportunity for green economic developments. Free and widespread allocations do not incentivize reductions, but rather reward pollution. If ARB adopts a Cap and Trade regulation, it should set a price on allowances that ensures allowances are not over allocated and that incentivizes reductions. Set a price on allowances from industrial sources that will incentivize reductions in CO_2 and criteria pollutants. (CVAQC, FRESNOMINISTRY)

Response: We do not agree that the proposed regulation over-allocates free allowances to the industrial sector, nor that we reward pollution. At the beginning of the program, most allowances should be distributed for free to help provide a soft start for the program. The allocation system is designed to reward those who have taken early action and have invested in energy efficiency and GHG emission reductions, and it will encourage continued investment in efficiency and clean energy in the future.

Free allocations will decline over time based on two main factors. One is the “cap decline” factor, which ensures that we will reduce emissions to meet the 2020 goal. The cap declines at 2 percent each year for the first compliance period, and then at 3 percent a year from 2015 through 2020. The second factor is based on the risk of emissions leakage. Staff has conducted an extensive analysis of leakage risk with a peer-reviewed methodology used in existing cap-and-trade programs. This methodology combines two considerations: trade exposure, and the degree to which greenhouse gas emissions influence the cost of the end product. Sectors which have high leakage risk will continue to receive a high percentage of allowances for free through 2020. Sectors with medium or low leakage risk will see reductions in their free allocations, beginning with the second compliance period in 2015. ARB has committed to revisit the leakage analysis before 2015, and to adjust leakage risk as necessary to reflect the results of the revisited analysis.

We agree that proceeds from the direct auction of allowances provide an opportunity for the most impacted and disadvantaged communities in California. Board Resolution 10-42 directs the Executive Officer to deposit a minimum of 10 percent of annual proceeds generated from the direct auction of allowances in the Air Pollution Control Fund for appropriation by the Legislature to programs and projects that reduce greenhouse gas emissions or mitigate direct health impacts of climate change and promote green collar employment opportunities in the most impacted and disadvantaged communities in California.

C-37. Comment: The level of free allocation proposed in the draft cap and trade rule will result in a huge wealth transfer from California's consumers to the industrial sector. In order to avoid this magnitude of corporate welfare, some part of this allowance value should be used to develop and promote low carbon-emitting industrial processes, as well as other societal benefits such as assistance transitioning for workers and small businesses. (UCS1, WALTERS, LUDLOW)

Response: We do not agree that the amount of free allocations is excessive. At the beginning of the program, most allowances will be distributed for free, to help provide a soft start for the program. The allocation system is designed to reward those who have taken early action and have invested in energy efficiency and GHG emission reductions, and it will encourage continued investment in efficiency and clean energy in the future.

As stated in Resolution 10-42, the Board directed the Executive Officer to deposit a minimum of 10 percent of annual proceeds generated from the direct auction of allowances in the Air Pollution Control fund for appropriation by the Legislature for programs and projects that reduce greenhouse gas emissions or mitigate direct health impacts of climate change. As further stated in Resolution 10-42, the Board agrees with several uses of allowances recommended by the Economic and Allocation Advisory Committee. In Chapter II and Appendix J of the Staff Report, we discussed several uses for Air Pollution Control Fund proceeds, including the creation of a Community Benefit Fund. Such a fund could be used to promote projects that simultaneously reduce GHGs and co-pollutants, finance adaptation/preparedness for climate change health impacts, create improvements to mass transit and land use planning, facilitate natural resource conservation, and support non-utility energy-efficiency programs. Additionally, we also discussed a Low Carbon Investment Fund to promote projects that support a green technology workforce training program. We will initiate a public process to develop recommendations on the uses of allocation proceeds. We anticipate that the uses for allocation revenue in the Staff Report will be further developed.

C-38. Comment: CARB staff proposes that free allowances in the first compliance period be followed by auctions in the second and third. We believe 100 percent free allocation for the first round is too high. SB-Cal agrees with language submitted to CARB by ETAAC. The level of free allocation proposed in the draft cap and trade rule will result in a huge wealth transfer from California's consumers to the industrial sector. In order to avoid this magnitude of corporate welfare, some part of this allowance value should be used to develop and promote low carbon-emitting industrial processes, as well as other societal benefits such as assistance transitioning for workers and small businesses. (SBCA2)

Response: We do not agree that the amount of free allocations is excessive. At the beginning of the program, most allowances will be distributed for free, to help provide a soft start for the program. The allocation system is designed to reward those who have taken early action and have invested in energy efficiency and GHG emission reductions, and it will encourage continued investment in efficiency and clean energy in the future. The regulation does not provide 100 percent free allocation to industrial emitters.

We do agree that part of the annual auction proceeds should be used in the community. Per Board Resolution 10-42, we will deposit a minimum of 10 percent of annual proceeds generated from the direct auction of allowances in the Air Pollution Control fund. These funds are for appropriation by the Legislature for programs and projects that reduce GHG emissions or mitigate direct health impacts of climate change, and promote green collar employment opportunities in the most impacted and disadvantaged communities in California.

C-39. Comment: I appreciate the desire to design a system that can protect against sudden or undue short-term economic impacts and "leakage" that might put California businesses and facilities at a disadvantage. Clearly, retaining industrial production within California has potential for greenhouse gas (GHG) emissions reductions, in and of itself. Moreover, the draft framework raises legitimate concerns about the additional costs from a cap and trade scheme on California's long-term economic prospects. Resolving these challenges are important goals, but might be achieved through mechanisms other than extensive free allocation of allowances, which was a key design flaw in the European Union (EU) emissions trading system. We must find the delicate balance between requiring the polluter to pay and the possible negative economic consequences of applying that principle. Free allocation of allowances will not necessarily result, for example, in the State or other large procurement entities purchasing California-produced or manufactured goods. While allowances might help offset a possible competitive disadvantage California industries could experience from industries out of state, allowances don't compel large procurers in California to procure within the California marketplace. Incentivizing in-State production and in-State procurement might have two possible GHG emissions reduction advantages: the emissions reductions achieved by the regulated in-state industry and the emissions reduction that could result from the avoided out of state or international transport. A specific carbon adder based on distance travelled might be considered. (ASMSKINNER)

Response: We do not agree that the amount of free allocations to be excessive. At the beginning of the program, most allowances will be distributed for free, to help provide a soft start for the program. We studied the strengths and weaknesses of all existing cap-and-trade programs, including the EU-ETS, and learned from these systems in developing our program to avoid over- or under-allocating allowances. We determined that a soft start, under the current economic conditions, dictates greater reliance on free allocation of allowances in the early years of the program. We view this free allocation as critical to avoid adding an immediate cost to covered industries that could inhibit their ability to invest in emissions reductions. Unlike in the EU ETS, free allocation relies on reported actual emissions and product data, minimizing the potential for over-allocation.

The allocation system is designed to reward those who have taken early action and have invested in energy efficiency and GHG emission reductions, and it will encourage continued investment in efficiency and clean energy in the future. The allocation system also takes production into account, so that in-state production is encouraged.

No Free Allowances to "Biggest Polluters"

C-40. (multiple comments)
Comment: We urge ARB to enact full auctions for all sectors from the outset of the Cap and Trade program. (CIPAL)

Comment: I am concerned and disappointed by the details of the cap and trade component. I don't think you should give away pollution allowances; you should charge for them. Polluting businesses will not do anything to reduce their polluting emissions if you just give away the pollution allowances. (BOOZ)

Comment: It concerns me that you might enact provisions allowing businesses that pollute free credits to pollute. This makes no sense; why reward polluters? If we are to have a comprehensive clean air policy and reduce carbon emissions then the biggest polluters must be held responsible to clean up their act. (SEECH)

Comment: I'm disturbed that you're considering carbon credit giveaways. This is necessary neither politically nor in practical terms and seriously undermines the purpose of the overall proposal. Please charge the utilities and other large polluters the true value of their credits. (LUVAAS)

Comment: I'm concerned with the details of the cap and trade component. By giving away the vast majority of pollution allowances, your proposal would financially reward the biggest polluters. This provides a clear disincentive for polluting businesses to reduce their greenhouse gas emissions, and therefore, would weaken the impact of California's landmark climate bill. Therefore I'm requesting that the final program include requirements that large-scale emitters pay for their emission credits. This will not only help fund the program, but also act as a powerful incentive to reduce emissions prior to any "trading." (GRASSETTI)

Comment: Please ensure that there is a minimum cost for all carbon emissions and that in the cap and trade schemes, no polluting is free—all permits must have costs associated with them. (DISENHOUSE)

Comment: Cap and Trade can result in no solution if too many pollution credits are given away for free. I, and judging from the defeat of the Texas Oil initiative in Nov, most Californians want implementation of AB 32. Pollution credits should be phased out quickly, or become exorbitantly expensive quickly, otherwise there's no incentive. Assessments of the amount of pollution should be made independently of the polluters proposals. (PRESSBURGER)

Comment: I suggest that all rights to pollute enter a market; there should be no free ride. (MILLERKENDR)

Comment: Please listen to the California electorate and implement AB 32 in a way that does not give away pollution allowances to the biggest polluters. This would remove the financial incentive for them to reduce their greenhouse gas emissions, which is the entire point of AB 32. (HARRISM)

Comment: I currently understand that the cap and trade component would give away the majority of pollution allowances. By doing so, this seems to reward the biggest polluters and weakens the intent of the climate bill. Please remove the allowance giveaways in the current rules and resume helping California to be a leader in this important endeavor. (STEINMAN)

Comment: I want to make sure that the largest polluters are held to the same standards as all the others. Please remove the huge giveaways that are in the rules for the largest polluters and hold all polluters to the same accountability and standards. (ROBERTSJ)

Comment: The California Air Resources Board is seriously out of touch with the citizens of California if it is contemplating giving away pollution credits to big polluters. The lopsided recent defeat of Proposition 23 should make that clear enough. Please do not coddle big corporations. Please do not reward big polluters for polluting by giving away pollution credits to them. (MACHEN)

Comment: I can't believe that you would even think of giving the worst polluters credits to do what they want. It is bad for the environment and it is obviously bad for people. California has been a leader for a long time and we need to make the rest of the nation take note. You need to be aware that your reputation as a law maker is on the line and being recorded. Do you want to be known as a sell out or do you want to stand up and lead the charge to a better society? I'd rather have a better environment! (NDRC)

Comment: While I agree with many of the steps outlined in the AB 32 Scoping Plan, I am concerned and disappointed by the details of the cap and trade component. By giving away the vast majority of pollution allowances, your proposal would financially reward the biggest polluters. This provides a clear disincentive for polluting businesses to reduce their greenhouse gas emissions, and therefore, would weaken the impact of California’s landmark climate bill. (FORMLETTER05)

Comment: Corporate polluters already transfer the health costs of their pollution to the public; do not add to that injustice by giving away the "emissions credits." (KENNEDYA)

Comment: I would prefer to see fewer permits given out for free, which allows the state to create winners and losers (mostly perpetrating the winners in the existing system in which pollution is free for polluters but taxpayers have to deal with the problems it creates). A real market system would not only be fair, it would also raise more money. (AMENTA)

Comment: Make sure that industry does not get a free ride by being allowed greater than needed allowances for pollution. Dentists, as small hazardous waste generators, must follow strict protocols regarding mercury and other waste into the water and landfill. Surely large corporations with much bigger profits can be held to high standards for air pollution. (STEINBORN)

Comment: Carbon pollution should be expensive for those who produce it. Please do not take it easy on businesses just because they have lots of money to spend lobbying for their interests. (RIEVE)

Comment: I do not favor your giving big business the opportunity to escape financial consequences for failing to reduce their emissions. This economy is market driven, and only by requiring businesses to pay for the consequences of their actions (or inactions) will they find the fortitude and the technology to make substantive reductions in their carbon footprint. (BOYDC)

Comment: Why are you even considering NOT auctioning 100 percent of allowance permits to industry? Is such corporate welfare really necessary? We are in the situation we are, precisely because industry has had a free ride in polluting our environment to the content of their bottom lines until now. Let's see a little accountability. (EICHELBERGER)

Comment: The industries that have been contributing carbon to the atmosphere shouldn't be rewarded by getting free allocations. Instead we need a free market that auctions off the available permit allocation and uses the funds to pursue additional actions that can help reduce emissions in other ways. (TERSOL)

Comment: Putting a price on carbon pollution will signal investors that there will be a cost to fossil fuel development. This principle should be applied throughout the program, so that there is a price for polluters to pay all the way down the line. The high value of the allowances to be freely distributed gives a permit to the biggest polluters and also constitutes a gross form of corporate welfare. The plan should quickly move to 100 percent auctioning, and have the money be used to subsidize the growing green energy industry in the state, which will help it to become competitive with China and continue to create decent jobs in the state. (MINAULT)

Comment: Auction the credits; don't give them to high-energy users. (DAWID)

Comment: I am quite concerned about one aspect of the cap and trade section of the Act, namely the proposal to give away most pollution allowances to businesses. This provision undermines the whole purpose of cap and trade, which is to create financial incentives to pollute less. Giveaways to large polluters make a mockery of the Global Warming Solutions Act. (HAYDEN)

Comment: The biggest polluters should not be rewarded. I am concerned and disappointed that the implementation of AB 32 will involve giving away pollution allowances to the biggest polluters. I have faith that your Board will not disincentivize the companies that have done the worst to hurt our environment to clean up their act. I see this as a big flaw in the cap and trade plan.

If multi-million and multi-billion dollar companies can sell and trade their allowances for a profit, I don't think it will make them change to more efficient use of our land, skies and water. We want them to invest back into California not sell off their allowances and slowly adjust their levels of pollution. They need to be held accountable to be part of the solution, and we need to create the incentives and punishments to make that happen. (EDIRISINGHE)

Comment: I am concerned that by giving away most of the pollution allowances for free, polluting companies could receive windfall profits without incentive to reduce their carbon pollution. (FORMLETTER07)

Comment: I am concerned about the giving of too many pollution credits to polluting industries. Please phase out this program as soon as possible. (BLACK)

Comment: I don't think that carbon emission allowances should be given away. We should auction these allowances so that we don't have to raise taxes to pay for enforcement and administration. (FREUND)

Comment: The air board should not give away carbon credits for free to polluters. Carbon fees are one of the single most important incentives for reducing emissions. (COHEN2)

Comment: We urge you to strengthen the cap and trade regulation by committing to maximize the use of auctioning as a method of allocating allowances. (UCS1, WALTERS, LUDLOW)

Comment: No free allowances for polluting industries. Economic and environmental analyses show that controls will benefit the state financially, both in revenue generation and in reduced healthcare costs from fewer pollutants in the air. (MORRISS)

Comment: We are concerned with the giving away of credits. (EBCHR)

Comment: Please do not indulge industrial polluters with giveaways. I know the recession has forced some changes in the original idea but please stand strong and do not give away millions in carbon allowances to oil companies and other big polluters. (BUSH)

Comment: Excessive reliance on free allowances could result in windfall profits for industry with the most emissions, creating a perverse incentive to pollute. (CIPAL)

Comment: Giving away permits is sheer folly. You should be selling these permits and strongly penalizing, fining, and making the polluters pay for their pollution. (MANGELS)

Comment: I recommend that the program be strengthened by requiring more of the state's largest polluters to pay for their global warming emissions at auction instead of giving permits away for free. (MSCG1, FORMLETTER06)

Comment: Maximize the use of auctioning as a method of allocating allowances. The level of free allocation proposed in the draft cap and trade rule is a gift to industry at taxpayer's expense. (VARON)

Comment: There is no way that giving corporate polluters freebies will work to fight global warming. They must pay a good price for these permits so that at least there will be some improvement via state use of the moneys gathered to mitigate their activities. (YURMAN)

Comment: Get it right. No credits for big time polluters in California. (BECKER)

Comment: Commit to maximize the use of auctioning as a method of allocating allowances. (CADMANS, UCS2)

Comment: I hope that you will implement a plan that does not let the big polluters gain from any of your actions. Not only do large industries get a free ride for their externalized costs, but I would hate to see them rewarded with more pollution credits. Please stand firm for the health of our citizens and our economy. (EARHART)

Comment: It would be a bad idea to provide financial incentives to businesses that pollute, but giving away the vast majority of pollution allowances under the plan currently proposed will do just that. Please reconsider this portion of the implementation strategy. (GLOVER)

Comment: Every polluter that is allowed a credit or a pass on emissions only prolongs the time it will take us to get to alternative sources of power and green tech. (GRIGGS)

Comment: I am opposed to the notion of giving away permits for greenhouse gas emissions. Sea levels are already rising, mostly due to rising ocean temperatures, and California has a significant area of productive agricultural land already located below sea level, an area known as the "Delta." Further rises in sea level put that production and the state's economy at risk, and no measure than can help to avoid or delay this should be ignored. (MOORE)

Comment: No corporation should be allowed pollution credits for free. (ROLLEY)

Comment: I think that major creators of greenhouse gases should have fiscal responsibilities to pay for the damage. Commercial enterprises will respond to regulations that affect their bottom line. The State should not be in the business of giving permits to pollute. (NC4)

Comment: Please honor the California voters' wishes and keep AB 32 robust by not giving away allowances to polluters. Like a vast majority of Americans, I am sick to death of corporate giveaways. (DUNGAN)

Comment: The proposed cap and trade rules weaken the impact of our climate bill by giving away the vast majority of pollution allowances. Seize the mandate for bold, meaningful action and remove the massive allowance giveaways outlined in the current rules. The currently proposed pollution allowances in the first couple years where they're given away is a multi-billion dollar transfer of wealth to dirty industry. This is something that needs to be addressed going forward before CREDO Action and our members will think that AB 32 and the Climate Solutions Act is being implemented to its fullest. (FORMLETTER09, CREDOACTION)

Comment: The proposed cap and trade rules weaken the impact of our climate bill by giving away the vast majority of pollution allowances. Seize the mandate for bold, meaningful action and remove the massive allowance giveaways outlined in the current rules. (FEICHTL)

Comment: No on 23 was a mandate from the people of this state for the strongest program implementation under AB 32. Free pollution allowances weaken the impact of our climate action, and should be reduced. The industries involved have profited from polluting for far too long, and these "gifts" will only allow them to continue to do so. Please strengthen the rules to achieve the strongest possible implementation of our climate law. (ZIMMERMANK)

Comment: CARB's plan gives the biggest polluters credits to pollute for free. Imagine receiving such a lucrative reward for having bad business practices. This multi-billion dollar giveaway also undermines the goals of AB 32. (WEISS)

Comment: It is imperative to make sure our actions promote good air quality. Giving credits to major polluters is adverse to your mission. Please continue to keep California in the lead for enforcing clean air measures. (SMULEVITZ)

Comment: Please recommend the right and most effective course in our new climate law, cap and dividends and no to industry giveaways. Let's put money back into the hands of the people of California. (KOWALICK)

Comment: Make all emitters pay for 100 percent of their greenhouse gas emissions. Pollution allowances should not be given away to oil companies and other large emitters. Allowances should be auctioned off, with the money used for clean energy, green jobs, public transit, and low-income consumers. (STEWARTJ)

Comment: Strengthen your program by requiring more of the state's largest polluters to pay for their global warming emissions instead of giving permits away for free. By forcing polluters to pay for the emissions they generate through the purchasing of permits in an auction, we can then re-invest that money in making homes and businesses more energy efficient, increasing public transit options, and developing wind and solar projects in California. (DUTTON, FUTRELL)

Comment: I believe permits need to be offered at a cost, to help fund energy efficiency and for developing alternative energy sources. (SUSTAINDESIGN)

Comment: Please do not give free credits to polluters. Instead, force them to pay for the emissions they create by buying permits at auction. The resulting funds can be used to sustain and promote additional measures for easing the swift transition to a better environment. (TRI)

Comment: Please protect the public interest by making polluters pay for their greenhouse gas emissions. Pollution allowances should not be given away to oil companies and other large emitters. (FORMLETTER10)

Comment: We can help to finance this reform by forcing polluters to pay for their emissions by buying permits, rather than just giving away permits for free. (CADMANL)

Comment: I suggest that a significant percentage of the allowances be sold rather than given away. By selling more and giving away fewer allowances, the allowances should have greater initial value and would generate more revenue to be used for other activities, which will reduce GHG emissions. (ASMDICKENSION)

Comment: It seems only fair, and quite reasonable, for the largest polluters to purchase permits to generate their toxic emissions, and for that cost to fund the growth of non-polluting energy systems in California; as well as supporting public transit in every possible local and regional way, as our population expands beyond our capacity to handle its transportation needs. (PAYNE)

Comment: Global Polluters are being held accountable to decrease California's greenhouse emissions by 2020. Emission decline to 1990 levels is a surmountable goal. Adding a fee to the permits, purchased at an auction, will directly supply the investment needed to create a green and carbon-free economy. (SANSONE)

Comment: Please make the polluters be responsible. Make them pay for the damages they have already made, clean up their businesses, and pay for permits. (LOUIN)

Comment: Please do not sell out to the biggest polluters by "giving them" credits to pollute. (CANNON)

Comment: Do not give tax credits to businesses that pollute our environment. (PETRALIA)

Comment: Don't give large corporate polluters and breaks or free credits. (HUNTER)

Comment: Free pollution credits should not be an option. (GRACE)

Comment: I worked very hard to defeat Prop 23 and feel strongly that there should be a limit on the number of pollution credits (below what you are proposing) and a quicker reduction of those credits. (SCHEIBE)

Comment: I love the fact that I live in California where we take environmental issues seriously. We have put in motion many laws that the rest of the states eventually enact. We passed Prop 23 which is a strong environmental proposition but it needs to be even stronger, not weaker. If the corporations can spend money to fight the law, they can spend money to pay for their actions and pollution. Make them pay for permits and make them abide by them. Europe is way ahead of us on environmental issues of all kinds and we should be the leaders. (SALERNO)

Comment: Credits should be auctioned or bought. Europe's system is a cautionary tale of setting the carbon price too low and giving away credits. (BEAZLIE)

Comment: CARB should clearly state in the regulation that it intends to move toward 100 percent auctioning, and leave an opening to do so. (UCS1, VARON, WALTERS, LUDLOW)

Comment: We should have learned the lessons of the EU. And I don't see any justification for why we have billions of dollars in basically handouts to already wealthy corporate polluters. So I'd like some justification as to why. (CPC5)

Comment: Polluters are rewarded, rather than forced to change behavior. With the majority of permits still allocated for free, the EU ETS is effectively providing a subsidy stream for highly polluting industry. (CTW)

Comment: I do not support a cap and giveaway system that financially rewards big polluters. When are we going to get serious about global warming? (CHAVEZ)

Comment: It is unconscionable that the largest corporate and industrial polluters, with the collusion of their republican climate deniers and lobbyists, would be given billions of dollars of giveaways. The entire world knows the non-negotiable American consumerist way of life is at the heart of this crisis. Facing our responsibility, stepping back into a leadership position, and evolving won't destroy our way of life—it will make it better than ever, and ensure that it can go on for many generations to come. (MASSMANJ)

Comment: I appreciate your efforts to implement CARB. However, please do not let the biggest polluters profit further from their pollution. (LIPPER)

Comment: Thank you for your work on greenhouse gasses. Please correct the one portion of the bill that would allow the worst offenders to continue polluting. (PAHRE)

Comment: Please don't allow the biggest polluters to pollute more; there must be a better way to implement this plan! (STEINMANA)

Comment: Let's not give the Earth away to the biggest users, seems very silly. Everyone should pay their share! (TAUSSIG)

Comment: In attempting to lead the nation in regulating carbon emissions, we should set a decent example and make sure business pays its share for the pollution it creates. (MURPHYH)

Comment: Why would you help companies avoid compliance? Get rid of the giveaway to business. Stop the political games and just require what we need to fix the air quality. (MURDOCH)

Comment: We need to get really tough with polluters - They need to pay for the damage they have done. Last Thursday, I attended The Cleantech Roadshow Seminar sponsored by Morrison-Foerster. The panel discussion was quite enlightening. I'd suggest you contact them and implement their suggestions. (MILLERWILL)

Comment: I think it is essential to have a plan to reduce greenhouse gases that does not allow the big polluters to further profit from their pollution. (SAYBLE)

Comment: I am concerned about what appears to be a "give-away" in the industrial sector. The EU made the mistake of giving away too much in free allocations, and as a result, have yet to see significant changes from that sector. Please do not make the same mistake. (LINNEY)

Comment: In order to have a substantial dividend, I strongly urge ARB to reduce the use of allocations and offsets. I don't think the oil and gas industry needs an offset. (CANFIELD1)

Comment: Polluters must pay for the byproducts and results of their actions. If they do not, they are permitted license to be an elitist class of Fed and government backed criminals with citizens as their victims. This must be ended. CA citizens want a future—not the dark coal-smoke and petro-poisoned dirty past. Thank you for saving my life, and your children from dangerous criminal polluters who don't want to have to pay for their crimes nor submit to much needed regulations. I demand my liberty, and I demand their crimes be stopped. Now it's already an hundred years too late. (CERELLO)

Comment: I want a plan to reduce greenhouse gases that does not allow the big polluters to further profit from their pollution. (GRAVELLE)

Comment: Thank you for your work to reduce polluters. Please, make it tougher. Make polluters pay. (CIBILICH)

Comment: I cannot believe that anyone would let business off the hook with the incredible debt this State has. This is a way to raise much needed capital, and business is awash in money that they are not spending because of the economy. (PRICEK)

Comment: Please adopt a plan to reduce greenhouse gases. It is very important to me and my family that the plan does not include inducements to big polluters that would benefit them financially. I firmly believe that the larger polluters should be penalized in the new plan. (LIEBER)

Comment: Please go forward with a plan to reduce greenhouse gases that does not allow the big polluters to further profit from their pollution. Do not compromise the greenhouse reduction plan with credits for large or small companies to continue producing greenhouse gases unabated. (HUGHES)

Comment: To deal with the already present global climate change catastrophe, we must act forcefully at the state and local levels. This is where the proposal in front of CARB to grant free allocations to industry fails miserably. We favor a True Cost Pricing approach to economics, where the price of goods and services embody their true environmental costs. Sending environmentally accurate price signals to consumers helps them make environmentally-friendly choices, while rewarding companies that act more environmentally sound. [We] favor carbon taxes over cap and trade schemes, because carbon taxes provide the most direct path to internalizing carbon costs and also provide more predictability in cost, are simpler and faster to implement, and are less open to manipulation through the political, legislative and/or regulatory process. For these reasons, many Greens are extremely disappointed in the CARB staff recommendation to implement a cap and trade scheme instead of a carbon tax. Nowhere could this be clearer than in our opposition to the staff's recommendations to grant free allocations to covered industry. The relevant issue with these free allocations is not leakage risk, but whether California can provide leadership by showing that an economic model that honestly and fully internalizes the environmental costs of burning carbon can work for consumers and producers. Research has demonstrated that even with no free allowances, and even for energy-intensive industries, changes in retail electricity prices are likely to be small.

The irony in the rationale to grant free allocations is as the staff report states, "Free allocation needed to minimize leakage will be maintained until adoption of equivalent carbon-pricing policies by other jurisdictions eliminates the leakage risk." Is 'waiting for others' what leadership is all about? Putting aside that the political conditions which led to the adoption of AB 32 in California may not even be present in other states for some time, what happens if other states actually do adopt the same model as California? Since the proposed free allocation model fails to accurately internalize carbon costs, we will then have proved little about industries' actual ability to truly adapt to such costs, and therefore only have delayed needed and sufficient action to our planetary crisis. The absurdity of this free allowance is exactly why many Greens tends to favor carbon taxes over cap-n-trade, and why if the CARB board adopts the staff recommendation, it would be an abdication of historic proportion of our state's environmental leadership role. In the post COP16 world, we desperately need such an example. Therefore I urge you to rise to the occasion and seize this opportunity for global leadership. Please eliminate the free allowances from the regulations governing the cap and trade program you approve. (GREENPARTY)

Response: We agree that an auction is the fairest and most transparent way to distribute allowances. We believe the system of allowance allocations we designed under the cap-and-trade program will transition California into a low-carbon economy. AB 32 mandates the California Air Resources Board to design all greenhouse gas regulations to minimize leakage to the extent feasible. At the beginning of the program, most allowances will be distributed for free, to help provide a soft start for the program. The level of free allocation will decline over time to settle at a level needed to prevent leakage. As the program progresses, we will auction a greater portion of allowances. Because allowances can be traded, the program provides incentives for those with the most cost-effective reduction opportunities to reduce emissions quickly. The cap-and-trade program is expected to result in increased investment in efficient buildings and technologies, and in advanced fuels. Implementation of the program will, however, shift investment and growth within the overall economy toward those sectors driven by the production of cleaner and more efficient technologies. This free allocation does not transfer wealth from Californian's to "dirty industry" as contended by some commenters. Because our analysis shows that most industries are not able to pass cost along to consumers, no 'transfer of wealth' from consumers to industry is expected to occur. Without the allocation, we would expect some production would shift out of State (leakage) as described above. Furthermore, an updating output-based allocation approach is an incentive to increase output rather than increase profit; this disincentivizes passing through compliance costs more than is necessary to minimize leakage.

In response to Green Party, we have performed an analysis of alternatives to the cap-and-trade program, including a carbon tax, and have found that none were as, or more, effective than a cap-and-trade program in carrying out the goals of AB 32. More information can be found in the Alternatives Analysis of the Staff Report.

Further, we have designed the cap-and-trade program to be sufficiently stringent to reduce GHG emissions to achieve AB 32 goals. Covered entities will be subject to a declining emissions cap, spurring installation of more-efficient and lower-emitting technologies. These entities must turn in allowances or a limited number of offsets to match their GHG emissions. Because there is a decreasing cap on emissions, overall emissions will go down.

Different Allotment of Allowances

C-41. Comment: Carbon allowances should be like voting. We have one person one vote. Why not one person one carbon allowance? A person should be able to benefit from selling his carbon allowances to, say, Chevron. There would be much less administrative overhead to tax carbon as it comes out of the ground or into California. (KRINOCK)

Response: We do not agree with the commenter's suggestion that each person should directly receive allowances. It would not be administratively efficient to allocate allowances to all residents of the State and ask them to participate in allowance trading. However, we recognize the public asset nature of the atmospheric carbon sink; in making decisions on allowance allocation we did consider the notion that the atmosphere is a global commons to which all individuals have equal claims.

We have performed an analysis of alternatives to the cap-and-trade program, including a carbon tax, and have found that none were as, or more, effective than a cap-and-trade program in carrying out the goals of AB 32. More information can be found in the Alternatives Analysis of the Staff Report. We also considered alternative points of regulation for the cap-and-trade program, including a fully "upstream" system where the obligation is assessed where fossil fuels are extracted or imported into California. We chose not to pursue this upstream approach due to administrative concerns including harmonizing with the existing framework for reporting of greenhouse gases which is primarily source-based.

Benchmarks

General

Use Best Practices

C-42. (multiple comments)
Comment: We support requiring the industrial sector to base product benchmarks on best practices and allowing benchmarks to be dynamic over time, so that the rule provides additional incentives for using best practices to reduce emissions. (SIERRACLUCA4)

Comment: The product benchmark for the industrial sector should be adjusted to reflect best practices instead of 90 percent of industry average. (NC1, NC2)

Comment: EDF recommends that allocation benchmarks for the industrial sector should be more ambitious, based on best available technologies and practices worldwide rather than reflecting the current performance of California operators. (EDF1)

Comment: We urge you to approve California's landmark greenhouse gas cap and trade program and change the industrial sector benchmark to an industry "best practices" level rather than an industry average performance level in order to incentivize industrial emitters to achieve "best practices" in their industry and become more efficient. (FORMLETTER04)

Comment: The product benchmarks for industrial pollution sources should reflect sector-wide progress in attainment of the best practice technology and should reward early adopters. The current proposal leaves these benchmarks unchanged for the whole nine years and thus blunts incentives for adoption of innovative emission reduction technologies and leaves cost-effective emission reductions on the table. Setting aggressive targets pays dividends, as can be seen in the electric power industry where adoption of the Best Available Control Technology has achieved a 99 percent reduction in power plant NOx emissions. (LUDLOW, UCS1, WALTERS)

Comment: Transition assistance needs to be clearly linked to opportunities for change and evolution. Allocation benchmarks should be based on best available technologies and practices. (EDF1)

Comment: Rather than setting the benchmark according to average performance, we encourage CARB to peg the benchmark to industry “best practices” to ensure that only the most efficient facilities have all their allowances covered, and poorer performing facilities will have to purchase allowances. This will incentivize all facilities to adopt industry best practices. (NRDC1)

Comment: Set the industrial benchmark at industry best practices, not industry average. This will ensure that only the most efficient facilities get all their allowances covered while less efficient and poorer performing facilities will have to purchase allowances. This will encourage all facilities to implement industry best practices. (ENVENTREP1, ENVENTREP2)

Comment: The product benchmarks should be based on known best practices in the sector, and not on sector average performance, as is currently proposed. If the average sector performance is below what known best practices could achieve, then industries that received allowances based on average performance will not be incentivized to adopt best practices. The benchmark should be set at current best practices and be revisited regularly to determine whether best practices have evolved. If so, the benchmark should be revised accordingly. (KUSTIN10, EBERHARD)

Comment: The current proposal leaves benchmarks unchanged for the life of the program. This may result in industries receiving excessive allowances that provide windfall profits. The benchmark should be set at current best practices and be revisited regularly to determine whether best practices have evolved. If so, the benchmark should be revised accordingly. The electric power industry, for example, is subject to Best Available Control Technology requirements for criteria pollutants, which has resulted in a 99 percent reduction in power plant NOx emissions from new power plants since the Clean Air Act was adopted. Benchmarks should be technology forcing in recognition of goals far beyond 2020. (KUSTIN10, EBERHARD)

Comment: We urge the Board to base product benchmarking on best practices rather than business-as-usual average performance for the whole compliance period. Benchmarks should be dynamic, reflecting the latest technology, knowledge and practice, and these should be technology-forcing in recognition of our future emission reduction goals and where we need to get to. (UCS4)

> **Response:** We believe our approach for setting benchmarks is appropriate. Best practices, technology forcing, or best available technology benchmarks are in essence benchmark stringencies, frequently used in setting emission levels or standards. In a market-based program such as cap-and-trade, the goal of benchmarking is not for setting the level of emissions. It is used to allocate free allowances to assist facilities with the cost of compliance, to prevent leakage and to incentivize them to reduce GHG emissions. We do not believe it is necessary to add provisions to the regulation that create benchmarks that update with time, such as when there is an update to current best practices. Even though the regulation sets static benchmarks used to calculate allowances for allocation, the two other factors—cap decline factor and assistance factor—do decrease with time. Thus, the stringency of free allowances will increase with time. In addition, ARB regularly reviews regulation, and the Board can direct us to revisit benchmarks when needed.

Benchmarking Methodology

C-43. Comment: Benchmarking approaches as proposed are confusing and may not be appropriate for certain operations or products, (i.e., benchmarking factors such as energy consumption and efficiency as a benchmarking method may not be representative of the fuel actually used in the manufacturing process which may, for example, be provided by boilers.) Benchmarking factors need to be refined to better address unique industry operations. In addition, it is difficult for companies to comment on the regulation when their benchmark has not yet been provided to them. (SDCHAMBER)

> **Response:** We modified the benchmarking methodology in section 95891 to provide more details and clarity. As directed in Board Resolution 10-42, we added the product benchmarks for industrial activities to Table 9-1 of section 95891(b).

C-44. Comment: An overly complex allocation method is unnecessary, particularly when resulting environmental impacts are determined by the cap and not the allocation. The development of appropriate comparisons among facilities will be extremely resource intensive for regulatory agencies, and in some cases, will not be possible given the complexity and variability of production processes. While benchmark studies may provide helpful narrative or directional information regarding technologies and processes, there are a large number of subjective decisions, assumptions and generalizations made when developing benchmarks for a particular process or product that ultimately render the benchmark itself inappropriate when applied to a specific facility. If actual best performing facilities or processes are used as a benchmark it may be impossible to know why a facility or process does not meet a benchmark given the complexity of the assumptions underlying the benchmark value. (AFPA)

> **Response:** We do not agree. Benchmarking in a cap-and trade program is one tool used in designing an allowance allocation system to maximize economic efficiency, minimize leakage, encourage innovation, and reduce the burden of compliance while leveling the playing field in emissions allowance allocation. The benchmarking does not require a facility to meet the benchmark level of emission efficiency. It is used to determine the compensation via free allocation of allowances to reduce carbon cost faced by affected facilities.

C-45. Comment: For facilities with allocations for purchased steam use, the proposed 110 percent cap on allowances could inappropriately limit allocations to Energy Intensive Trade Exposure (EITE) entities undermining the goal to prevent leakage. As written, this section in conjunction with the ISOR suggests that the 110 percent limit applies to allowances received for purchased steam. Since allowance allocations are tied to purchased steam (in addition to onsite emissions), the proposed restriction might needlessly and inadvertently reduce allocated allowances. ARB should clarify in its final rule that the restriction in section 95891(c)(2) does not apply to allowances allocated for purchased steam at EITE entities. (DOWCHEM1, DOWCHEM2, DOWCHEM3)

> **Response:** We modified section 95891(c)(2) of the regulation to clarify how the restriction applies to purchased steam.

C-46. Comment: CARB should not expand the process for establishing an EEB to depend on electrical consumption data. (SMITHS)

> **Response:** The Emissions Efficiency Benchmark (EEB) for electricity $B_{Electricity}$ was used only for electricity sold or provided to off-site end users in calculating allowances to be allocated using the energy-based benchmark method in section 95891(c).

C-47. Comment: There is a need for adequate review of any sector-specific EBB-setting methodology proposed by CARB Staff. (SMITHS)

Response: We agree. In addition to reviewing available information and approaches, such as the European Union's Emissions Trading Scheme (EU ETS), we also get input on developing the methods we use from stakeholders through public workshops, ARB Board hearings, facility and sector-specific consultations, and in comments on the Staff Report and 15-day changes to the regulation.

Describe the Thermal Energy Methodology

C-48. Comment: The methods to establish thermal energy historical baselines in Section 95891(c)(3) are not clearly specified. Dow recommends that ARB specify the methodology that must be used to establish "average annual baseline values" and "historical baseline annual arithmetic mean amounts." Key terms and methods are not defined in the proposed regulation. Baselines cannot be determined with certainty until the methods for deriving baselines are more clearly specified in the regulation. (DOWCHEM1)

Response: We agree and modified section 95891 of the regulation to provide more detail and specificity for the energy-based (previously thermal energy-based) allocation calculation methodology.

Data Sources

C-49. Comment: GANA supports reliance upon multi-year output averaging for allocations. (GANA)

Response: In developing production efficiency benchmarks, we relied on representative data provided by facilities within a sector. In some cases, multiple years of data were available as the basis of the benchmark. In all cases we relied on data provided in our MRR reports if appropriate, or secondarily on data obtained during ARB sector surveys. We also collected data from industries specifically for the benchmarking analysis. When industries indicated that particular data years were not representative of actual operation, we relied on information provided to us voluntarily. In many cases, we used multiple data years if data were representative of actual industry operation.

C-50. Comment: Currently Section 95891(c)(1) prohibits ARB from using third-party verified 2008 data reported to the California Climate Action Registry (CCAR) as a basis for determining the average annual baseline values used to determine a number of allowances to be allocated. For Dow and other similarly affected facilities, CCAR inventories provide accurate third-party verified data. Dow Pittsburg voluntarily reported to CCAR for calendar years 2006 through 2008. Dow recommends the following modification to Section 95891(c)(1) of the draft regulations:

(1) Data Sources. In determining the average annual baseline values, the

Executive Officer may employ all available data reported to ARB under the MRR for data years 2008-2010 and third-party verified data reported to the California Climate Action Registry for data years 2000-20078. (DOWCHEM1)

Response: We agree and modified section 95891(1) of the regulation to allow the use other years of data reported to the California Climate Action Registry (CCAR).

C-51. Comment: Eleven years of historical greenhouse gas emissions data are not typically available for many entities. Section 95891(c)(2) establishes an absolute limit on the level of free allocation under the thermal energy-based allocation relative to historical GHG emissions levels from a given facility. This limit is set at 110 percent of the maximum annual emissions during the 11 year baseline period, from 2000 through 2010. A requirement to independently verify all intervening years would be expensive, time consuming and unnecessary. Dow recommends that ARB specify how the eleven year emissions baseline would be produced. Dow proposes the following language be added to Section 95891(c)(1) to address this issue:

(1) Data Sources. In determining the average annual baseline values, the Executive Officer may employ all available data reported to ARB under the MRR for data years 2008-2010 and third-party verified data reported to the California Climate Action Registry for data years 2000-2007. For years in which verified data are not available, covered entities may pursue either (a) reporting of missing years with The Climate Registry, (b) utilize third-party verified data reported to other entities as approved by the ARB, or (c) utilize third-party verified baseline reports of annual data that are reported to the local Air District for fuel use (as filed with annual data for air pollutant emissions) and annual bills from vendors of purchased steam. (DOWCHEM1)

Response: We modified section 95891(c)(1) and (2) to address this concern.

C-52. Comment: Operational variability at some facilities could end up masking early action and prevent the intended rewards from being recognized. Thus, the intended reward could actually be a penalty. Dow recommends that Section 95891(c)(1) be removed. ARB's Initial Statement of Reasons (ISOR) indicates that the intent of this section is to reward facilities for efficient steam use and "to prevent the level of this reward from becoming excessive." Dow Pittsburg has made many investments in energy efficiency and renewable energy since 2000. Dow Pittsburg would be a worthy recipient of rewards for early actions. Despite ARB's intent, the proposed provision might more likely penalize Dow Pittsburg for its operational variability than reward Dow for its historic de-carbonization efforts. (DOWCHEM1)

Response: We modified section 95891(c)(1) to address this concern.

Significant Growth

C-53. Comment: Using a historical baseline to determine allowance allocations results in an unnecessary penalty for operational variability from year to year as well as for growth. For industrial boilers and heaters, a thermal intensity benchmark per ton of product could be applied to ensure that efficiency does not decrease significantly during periods of growth. Dow proposes a new definition and the following new Section 95891(c)(5):

New definition in Section 95802(a)
Significant Growth. "Significant growth" means annual increases in steam and/or thermal use of up to 50% over the historic baseline at EITE entities.

New Section:
Section 95891(c)(5) Significant Growth. If significant operational growth occurs, baseline values for annual steam and/or thermal energy use shall be re-assessed based on expected activity levels as determined by the Executive Officer

Rationale: Significant operational growth will render a historical baseline determination inaccurate as a basis for determining allowance allocations. Existing facilities that change significantly should have their baselines adjusted so that their carbon costs may continue to be covered. This language parallels the "new entrants" language in section 95891(c)(3) and therefore, would also establish greater parity between expansions at existing facilities versus construction of new facilities.

Alternative Recommendation: Alternatively, Dow recommends the following modification to section 95891(c)(3) of the draft regulations (additions in underline, deletions in strikethrough):

"(3) New Entrants. Covered entities of facilities that were not in operation prior to 2011 and are eligible for free allocation under the thermal energy-based methodology shall be assessed a baseline annual steam and/or thermal energy use values based on expected activity levels as determined by the Executive Officer. For purposes of this provision, "new entrant" includes an existing facility that increases its reliance on efficient industrial boilers."

Rationale: This change would place expansions at existing facilities on an equal footing with construction of new facilities. Providing allowances to encourage incremental reliance on efficient industrial boilers will promote achieving key objectives of the Scoping Plan. Such parity is needed to maintain competition. (DOWCHEM1)

> **Response:** We disagree and do not believe it is necessary to add provisions to the regulation to update the baseline in the case of increased energy use at an incumbent facility. Our preferred allocation approach is to use product-based benchmarks, which are used for the majority of facilities under the cap-and-trade program. In the case of product-based allocation, growth would increase the

amount of product, thereby increasing the amount of free allocation. The energy-based allocation methodology is not the ideal method, and is only used for a small number of facilities whose products currently pose challenges to the use of the product-based allocation methodology. We believe that allowing for incumbent facilities in the energy-based allocation methodology to obtain more allowances for increased energy use may create perverse incentives to increase greenhouse gas emissions. If possible, we would like to work with facilities in the energy-based allocation methodology to develop product benchmarks and switch to the use of product-based allocation methodology for all facilities that are interested in expansion.

Non-Operation

C-54. Comment: CARB needs to clarify how it would determine a facility "output" of a unit that is currently non-operational. The use of the term "unavailable data" is unclear. The regulation should clarify that the calculation for annual average output should not include periods of non-operation. (PMTPETRO1, WIRA1)

Response: We modified section 95891(b) and added a “true-up” term ($O_{a,trueup}$) for adjusted outputs not properly accounted for in prior years’ allocations in the equation for calculating product benchmark-based allocations. We believe this modification, together with the annual updating of product outputs, adequately addresses production fluctuations.

Calculate Benchmarks Appropriately

C-55. Comment: Appropriate calculation of benchmarks is essential so that industry sectors know anticipated cost of compliance, and can plan for future operations, projects, expansion, etc. Under the current regulation, a facility that is more efficient than the proposed benchmark will receive more of its allowances freely while those less efficient facilities will have to purchase additional allowances. We agree with this concept so long as the benchmarks are set correctly. (CALCHAMBER1)

Response: We agree but do not believe it is necessary to add provisions to the regulation because our approach is expected to allow more-efficient facilities to receive more free allowances than facilities that are less efficient.

Set Benchmarks Early

C-56. Comment: It is our recommendation that work on benchmarking be completed as soon as possible so that affected parties can actually calculate their exposure and accurately forecast budgets for 2012. Affected entities need at least a year to prepare for the new cap and trade regime commencing in January of 2012, and the gaps in the current regulation make it difficult to accurately develop budgets and make investment decisions. (CACC)

Response: We agree and the product benchmarks for industrial activities were added per Resolution 10-42, and presented in Table 9-1 of section 95891(b). With the new compliance starting date of January 2013, facilities should have sufficient time to plan their compliance strategies.

C-57. Comment: The decision to allocate by benchmarks from the outset, rather than according to historical emissions trends, is very welcome and should help to prevent the accrual of ‘hot air’ in the system, which currently be-devils the EU system. The fact that benchmarks are tied to productivity, within an overall fixed cap, is also welcome as this again prevents rewards being handed out to those who are merely cutting back on production and helps to incentivize genuine investment in abatement. Officials should be wary of entering into lengthy discussions with industry about the number and nature of the benchmarks. There will be a tendency for every subsector of industry to plead for special treatment, proliferating the number of benchmarks, and arriving back at something close to historic grandfathering, which is clearly sub-optimal. (SANDBAGCC)

Response: No response necessary.

Cement

C-58. Comment: CARB calculates allowance allocations using a lagging estimate of output, which will result in persistent and severe under-allocation to the cement industry. (CSCME2)

Response: We agree and modified section 95891. We will adjust for any output not properly accounted for in prior years starting in 2014, using actual 2012 output.

C-59. Comment: CARB's lowering of the benchmark for all industries is arbitrary, inequitable, and undermines its efforts to minimize leakage. A critical decision in the construction of a benchmark is determining its stringency. In its Staff Report, CARB states that staff’s current thinking is that the targeted level of stringency would be created by evaluating each industrial sector’s emissions intensity during a historical base period and targeting the benchmark to allocate 90 percent of this level per unit product. For a variety of reasons, CSCME strongly disagrees with this approach of applying a uniform 10 percent "discount" to industry averages in order to form benchmarks. (CSCME2, CSCME3)

Response: We disagree and do not believe it is necessary to add provisions to the regulation to modify benchmarking stringency. We believe that benchmark stringency should reflect the emissions intensity of highly efficient, low-emitting facilities within each sector. In the Staff Report, we described a targeted level of stringency created by evaluating each industrial sector’s production-weighted average emissions intensity during a historical base period and then using that level to target the benchmark to allocate 90 percent of this level per unit product.

In subsequent work evaluating the benchmark values, we found that the stringency approach proposed in the Staff Report worked for many sectors but, in some cases, would set the benchmark at a level that was more stringent than the current emissions intensity of any existing California facility. For the sectors for which this occurred, we selected a benchmark based on the "best-in-class" value (i.e., the emissions intensity of the most GHG-efficient California facility).

C-60. (multiple comments)

Comment: CARB's failure to include indirect emissions in the benchmark is likely to significantly increase the risk of leakage. Another critical decision in the construction of an industry benchmark is the scope of emissions included in the numerator, in particular, the decision to include or exclude indirect emissions. As recognized by CARB in the Staff Report, the risk of emissions leakage is a function of the net increase in total policy-related costs, including the costs associated with direct and indirect emissions. The impacts associated with a unit increase in indirect costs, including those from electricity, are indistinguishable from a unit increase in direct costs, as both increase leakage. Increases in electricity prices are of paramount concern for many energy-intensive firms, including the cement industry. It is estimated that electricity prices represent 10 percent of total costs and 20 percent of variable costs for California cement facilities. Failure to offset these costs through policy design will result in increased leakage in cement and other industries. Despite these concerns, CARB proposes to exclude indirect emissions from the benchmark. (CSCME2)

Comment: ARB's proposal does not ensure that EITE entities costs associated with electricity purchases will receive adequate cost containment coverage of their emissions. Nor do the proposed regulations adequately specify requirements to the IOUs and POUs for cost recovery for electricity purchased by EITE entities.
Recommendation: ARB should address these competitive impacts in one of three ways:
1. ARB could provide an EITE entity a direct allocation of free allowances for power purchased from a distribution utility. To avoid double counting, ARB could then exclude these allowances from the allocation of free allowances to the entity's serving utility, OR
2. Alternatively, ARB could require the distribution utility to share the benefits of free allowance value with EITE entities through direct monetary rebates.
Dow recommends that ARB provide that IOUs and POUs must convey free allowance value to an EITE entity through a rebate or bill credit, rather than through continued or increased access to energy efficiency programs or through other future policies that will be developed by utilities and their governing boards and/or agencies, OR
3. Finally, ARB could require utilities to provide EITE customers with a direct allocation of free allowances for power purchased from the utility. No adjustment would be required to avoid double counting in this example.
Rationale: Competitiveness for EITE facilities can be maintained only to the extent that the proposed regulations are modified to ensure that all GHG compliance costs are recovered by EITE entities.

ARB does not intend to provide free allocation of allowances for the carbon costs associated with imported power because it assumes that carbon costs associated with these imports will be alleviated by the allocation of allowances to its interconnected utility. In Appendix J, ARB states, “Indirect carbon costs arising from purchased electricity from the grid will be reduced through compensation from distribution utilities that are given allowance value for the purpose of ratepayer protection.”

The proposed change would empower the capped entity to make the most cost-effective investments in GHG reductions rather than prescribing a particular approach. If an EITE entity procures power from an electric utility, the regulation is unclear about the level of coverage, nor how the value of allowances received by the utilities will be reconveyed to EITE customers. These details need to be specified. To achieve ARB’s stated objectives, the proposed regulation should be revised to provide explicit requirements that will ensure that carbon cost recovery by EITE entities for purchased electricity can be measured and ultimately achieved. (DOWCHEM1)

Comment: The proposed regulation’s use of the term “on-site” power is unclear. Dow recommends that ARB clarify this term with regard to assistance to Energy Intensive Trade Exposed facilities that purchase electricity from third party electricity generating facilities co-located at the EITE facility. Dow recommends that ARB assure that EITE entities will be fully compensated regardless of which entity they purchase electricity from. Effective transitional assistance to industrial facilities requires recovery of GHG compliance costs associated with power purchased from a utility or non-utility.
Rationale: In discussing thermal-energy based equations, the ISOR states, “Electricity purchased from off-site is not part of the thermal energy-based allocation equation but receives indirect compensation through [the] distribution utility to offset the expected indirect GHG costs, as described in Section 95892.” With these changes, the carbon costs associated with electricity consumed by all EITE entities will more likely be covered in a competitively neutral way.

ARB’s proposed regulations leave open critical gaps that may compromise its ability to adequately provide transition assistance to EITE entities. ARB proposes to provide free allowance allocations to EITE entities to “avoid imparting undue initial economic gain or loss” in the early program years and to prevent leakage. ARB notes that current competitiveness is maintained if the free allocation covers all of the EITE’s carbon costs:

Current competitiveness is maintained if: Free allocation = carbon costs – carbon cost recovered.

Table J-7, however, highlights a major gap in this framework. As shown below, while ARB intends to directly reduce carbon costs associated with heat consumption and on- site energy consumption, an EITE facility will be exposed to GHG compliance costs associated with “imported” power. (DOWCHEM1)

Response: We do not believe it is necessary to add provisions to the regulation to include indirect emissions associated with electricity at this time. In the program framework, an adjustment factor was not made for power purchased in establishing the product-based benchmarks. This is because purchased power may not create an indirect carbon cost in all California utility service territories. It is ARB's goal to see a carbon price properly embedded in all utility rates. If and when this occurs, the compensation for these indirect carbon costs could be incorporated into the product benchmarks (or reductions in these costs created in some other fashion) to help minimize leakage. We will revisit this issue once the California Public Utilities Commission Proceeding addressing utility costs and revenue issues associated with greenhouse gas emissions concludes.

C-61. Comment: CARB uses a data sample for establishing benchmarks that does not fully recognize historic investments in GHG efficiency or fully reward early action. Another critical issue in the construction of a benchmark is the choice of the data sample, including both the timeframe and the geographic scope. In establishing the benchmark for the California cement industry, CARB proposes to use California data from the 2009 Mandatory Reporting Rule ("MRR"). CSCME strongly disagrees with this approach for several reasons. First, by using California data, the benchmark will not fully recognize historic investments that California cement manufacturers have made in GHG efficiency relative to their out-of-state competitors. Second, the benchmark will not fully reward early action that the California cement industry has taken since the adoption of AB 32. (CSCME2)

Response: We disagree and believe the MRR 2009 data does match historical emissions levels and reflects historical investments in GHG efficiency. We reviewed California, national, and international emission/production data available for the past several years for the cement sector. These include the MRR, ARB industry survey, national data compiled by the Portland Cement Association (voluntarily provided by the Coalition of Sustainable Cement Manufacturing & Environment), and international data compiled by the World Business Council for Sustainable Development. We found that the MRR 2009 data was representative of historical emission levels over the past couple of years for California plants. We did not find a significant change in emission intensity due to early action (e.g., increase amount of biomass used in lieu of fossil fuel). We identify and use data from the most efficient operation among California facilities.

C-62. Comment: CARB ignores critical qualitative evidence in determining the trade exposure of the California cement industry, including nearly two decades of antidumping rulings. The California cement industry's extreme vulnerability to imports is evidenced by nearly two decades of antidumping rulings by the ITC. In support of these rulings, economists at the ITC analyze public and confidential firm-level data on price, market share, and profit. This is precisely the information that CARB would need to make a complete and accurate assessment of cost pass through ability. CARB should reclassify the California cement industry as "highly trade exposed." The weight of both quantitative and qualitative evidence conclusively demonstrates that the California cement industry has a high trade exposure, faces a high degree of competition from unregulated entities, and has extremely limited cost pass-through ability. CSCME recommends that CARB incorporate this evidence into its determination of the cement industry's trade exposure and place it within the "highly" trade exposure category. Although CARB has already designated the cement industry as "highly" leakage exposed, such a designation does not account for the fact that the cement industry's leakage risk is far beyond that of any other California industry's assessed risk. The combination of high trade intensity and high GHG intensity creates an extremely high risk of leakage for the California cement industry and justifies additional measures to minimize leakage in implementing AB 32. (CSCME2)

> **Response:** We do not believe it is necessary to add provisions to the regulation because the California cement industry is classified as a "high leakage risk" category and is therefore eligible for the highest level of compensation that ARB can provide in free allowance allocations for transition assistance and to mitigate leakage risks. We used a "trade intensity" metric to quantify the magnitude of competitiveness, as described in Appendix K of the Staff Report. Using that method, the cement industrial sector was placed in a medium category for trade intensity, with a trade share of 16 percent. However, we agree that competitiveness can be affected by various causes that may not be captured by a single metric. We intend to conduct additional analysis starting in 2013 while continuously monitoring the impact of the program on industrial sectors' competitiveness.

C-63. Comment: Create dynamic product output based benchmarks that reflect best practices in the cement sector. (UCS2, CADMANS)

> **Response:** We agree and set a best-of-class benchmark based on adjusted clinker and mineral additives produced for cement. The results are presented in Table 9-1 of section 95891(b), and the analysis is presented in Appendix B to the 15-day notice of changes to the proposed regulation.

Food Manufacturing

<u>*Product-Based Benchmark Not Appropriate*</u>

C-64. (multiple comments)
Comment: With approximately 400 agricultural commodities and even more byproducts on store shelves, it will be quite problematic for CARB staff to attempt to create product-based benchmarks for food processing. Management of a product-based system is beyond the scope of CARB's expertise. (ACC3, CALFP1)

Comment: Adopt the energy-based benchmark ("fallback") for food processors permanently. (CALFP1)

Response: We allocated free allowances to food processing facilities using the energy-based allocation calculation methodology, which bases allocation on the fuel and steam use of a facility.

Energy-Based Benchmark is Appropriate

C-65. Comment: Energy-based benchmarks are more acceptable to the food processing industry and would create a more streamlined system for CARB regulators. However, due to industry expansion, some flexibility should be allowed within the system to achieve collective goals of CARB and food producers.

A well-known industry set of standards and efficiency promulgated by a respected group, the American Society of Mechanical Engineers, should be used in place of CARB's proposed efficiency rule. These standards are familiar to processors, and were created over many years of study by a third party trade association. (ACC1, ACC3)

Response: The energy-based allocation calculation methodology was used to allocate allowances to food processors. As a clarification, we are not using an ARB-proposed efficiency rule for boilers, but are using, and recommending that affected facilities use, ASME PTC-4 for estimating boiler efficiency to estimate steam production.

Energy Efficiency Credit

C-66. Comment: Food processors have implemented energy efficiency measures for many years. These projects include flue gas recirculation and economizers for boilers as well as energy efficiency audits by third parties and utilities to optimize energy use. While more can be done, implementing the next generation of efficiency upgrades can be cost prohibitive for some facilities. CLFP recommends that CARB broaden the scope of qualified opportunities to receive credit for these investments in addition to clean burning fuels, such as Combined Heat and Power (CHP). (CALFP1)

Response: We believe that the energy-based allocation methodology provides both incentive for innovation and credit for early action.

Recognize EITE Nature of Food Manufacturing

C-67. Comment: In establishing an emissions benchmark, it is vital that CARB recognize that food processing is an energy intensive and trade sensitive sector that has a vital role in maintaining the California economy, and will be the key factor in any Central California economic recovery. (CALFP1)

Response: We recognize the role of food processors in the California economy and have designed an allocation system that accounts for the sector's contributions.

Comment: We are concerned that a three year average will produce a more punitive benchmark that does not reflect accurate energy needs. Because of the unique factors identified in the food processing industry, it would be more accurate for the industry benchmark to be set at the highest emissions level encountered in any one year operating period. Special consideration should be made for new facilities that do not have the operating history. For instance, new facilities with shorter baseline periods, in cases less than three seasonal years, should use the maximum full season operating emission rate. (CALFP1)

> **Response:** We disagree that it would be appropriate to allocate to food processing facilities based on the highest emission level encountered in any one operating period. The result of such an approach would likely be an allocation of allowances well beyond actual emission levels. Sale of these excess allowances would lead to windfall profits for the recipients of this free allocation. We did not adopt this approach.

Boiler Size Assumptions and Efficiency Benchmark

C-68. (multiple comments)
Comment: Staff assumptions regarding boiler size do not reflect agriculture or food processing industry standards or practices. Boilers currently used by most California food processors are larger than the averages that staff cites in support of its regulation. Boiler sizes range from 93 MMBtu to 183 MMBtu per hour natural gas input, significantly larger than the published estimates. Additionally, staff fails to take into account that all of the large processors return the boiler condensate to a deserter tank for reuse in the boilers at rates that are as high as possible and that the boilers utilized by food processors have blow down heat recovery units on all boiler systems and maintain steam traps in proper function. (CALFP1)

Comment: Staff has set boiler efficiency benchmark at 85 percent. This standard is set based on staff's own set of equations. Staff's need to employ a simple method for establishing CO_2e for individual industrial sites is understandable. However, staff's equations do not take into account the actual efficiency of steam production or end use in the food processing industry. This means facilities with very inefficient systems but low use won't be taxed at the same rate as a highly efficient facility with higher use. Order staff to utilize accepted ASME standards in calculating boiler efficiencies for food processors. (CALFP1)

Comment: I'd like to bring up the boiler efficiency calculations that were used for the allocation equation in J-4. In order for food processors to determine the annual steam production, it's necessary to use ASME equations for boiler efficiency. The only numbers available to food processors are fuel use and boiler efficiency. We use universally accepted methods for efficiency calculations, so we don't have an annual steam volume unless we can calculate it using our efficiency. Staff uses a number of 85 percent for fuel efficiency for their benchmarks for an efficient boiler. I assume that came from the ASME equation. You're going to push this efficiency and these boilers that we use to an extent that when you get above about 90 percent and you reach firing rates, it doesn't take long for something to go haywire and a boiler will explode. We need to continue to work with staff, and I think they will. And I appreciate the work that we've put in and the time. (DMF)

> **Response:** In developing the regulation, we developed the steam benchmark used in the energy-based allocation equation based on a highly efficient boiler of 85 percent efficiency. We selected this boiler efficiency benchmark after consideration of the industrial boiler efficiency technologies required to generate offset credits under the U.S. EPA Climate Leaders Program. A value of 85.7 percent for steam generation using natural gas is listed in the Department of Energy website. We are using, and we recommend affected facilities use, ASME PTC-4 for estimating boiler efficiency to estimate steam production. In gathering facility data for allowance allocation purposes, we determined that the default boiler efficiency factor of 85 percent for deriving the steam emission efficiency benchmark (B_{steam}) is achievable, stringent, and appropriate. Boiler size is not used in the ASME PTC-4 boiler efficiency calculations, and we are not attempting to use the parameters mentioned to set standards for boiler efficiency or food-processing technology standards.

Glass

Support

C-69. Comment: GANA supports establishment of separate CO_2 equivalent emission intensity benchmarks for container, flat, and fiber glass manufacturing sectors. (GANA)

> **Response:** No response necessary.

Use Nationwide Benchmark

C-70. (multiple comments)
Comment: GANA strongly urges CARB to include all applicable float glass furnaces operating nationwide in the establishment of the emission intensity benchmark for the flat glass sector, as opposed to restricting such scope to only California or the WCI region as the draft regulation currently contemplates. This will ensure that the benchmark established for purposes of applying CARB's cap and trade regulation is fully representative of actual industry operations over the course of a furnace campaign. During the course of a flat glass furnace campaign, many factors or variables will affect the GHG emissions intensity of the flat glass operation, including the age of the furnace, the types of products made, the types of burner technologies employed, the types of downstream value added processes employed, and repair periods such as cold repairs and hot holds. A benchmark developed on the basis of just the three float glass operations in California would not be representative of standard industry operations. In order to develop a nationwide average of flat glass industry operations, GANA suggests that CARB utilize the data that industry will submit in 2011 for its 2010 emissions as

required by the U.S. EPA federally mandated GHG reporting program. The data that will be submitted as part of the federal mandate will be verifiable, cover all or almost all flat glass furnaces nationwide, and include production data to an extent that it can be used to establish an accurate and representative industry average emission intensity. (GANA)

Comment: Establish an EEB for the container glass manufacturing sector employing nationwide data, not California-only data. (SMITHS)

> **Response:** We analyzed credible data available iteratively in deriving product benchmarks. On a case-by-case basis, national data may be used for developing the benchmark, but most frequently it is used as a check for the benchmark developed using California facility data. We consider various factors in establishing a product-based benchmark for free allowance allocation. We believe that the focus of benchmarking under cap-and trade is to create the correct incentive for California facilities to reduce GHG and protect them from leakage. This means that, in most cases, it is appropriate to avoid benchmarks differentiated by technology, fuel mix, size and age of the facility, climate circumstances, or raw material. Ensuring that all GHG emissions-abatement options remain viable is an integral part in our development of product benchmarks.

C-71. Comment: California's fiber glass insulation plants are the best performing in the nation. It is important to compare California's performance to that of the other mineral wool plants throughout the United States, as they would be the primary source of fiber glass insulation for the California market if the industry's California plants cannot supply the market. Based on the average performance of U.S. plants, NAIMA recommends a benchmark for the fiber glass (mineral wool) industry of 0.463 MT CO_2E per metric ton of glass pulled. One hundred percent of the average U.S. direct and process emissions are 0.463 MT CO_2E per metric ton of glass pulled. (NAIMA)

> **Response:** We analyzed California's fiber glass manufacturing activities in establishing a benchmark per short ton of fiber glass pulled. We believe that the focus of benchmarking under cap-and trade is to create the correct incentive for GHG reduction while protecting against leakage. Like the benchmarking of other sectors, the use of California production activities is appropriate. In our analysis of data, we used national and international data to check the benchmark we developed in Table 9-1 of section 95891(b). The benchmark in SI units is comparable to the suggested benchmark.

<u>Data Sources</u>

C-72. Comment: If CARB determines upon evaluation that none of the data available to it through the federal mandatory GHG reporting rule or other existing reporting programs is adequate to support the above proposals, then GANA requests a meeting with CARB to discuss other methods by which existing information may be supplemented or made available through mechanisms that can ensure the confidentiality of individual company information. (GANA)

> **Response:** We stand ready to meet and discuss issues related to the development and implementation of the regulation through mechanisms that can ensure confidentiality of individual company information.

Averaging Period

C-73. Comment: GANA proposes lengthening the output based averaging period to five years with provisions to drop the high and low years in order to account for furnace maintenance cycles in the flat glass industry. Using the average of three years output to calculate projected allocations will still be problematic and materially inadequate if that three year time period includes a year in which a hot repair, hot hold, or furnace cold tank repair (CTR) takes place. During a hot hold (idling conditions), no product is being produced but the furnace is kept hot. On average, a typical regenerative furnace uses 50 percent of the energy needed to operate the furnace at full production capacity, in order to maintain the heat in the furnace during a hot hold with no production. This amount of energy represents the minimum amount of heat needed to run the furnace and is independent of output. Hot holds are generally done for emergency repairs of the furnace and are not done very often. They can generally last up to a couple of months so they can affect the allocations given for a site in the following year when production is full under the currently proposed allocation method. Similarly for CTRs, there are periods of time in which fuel is being combusted for heat-up and initial raw material charge, but no product is being produced. Under the current draft regulations, these activities would result in under allocation for the following year during normal production. In order to account for this standard industry maintenance practice in a manner that reduces the likelihood of leakage while achieving the goals of the cap and trade program, GANA urges CARB in the final regulations to calculate the output factor used in the product-based allocation formula for the glass sector from the production in years t-2, t-3, t-4, t-5 and t-6, dropping the year representing the lowest production and the year representing the highest production and the arithmetically averaging the remaining three years to arrive at the output factor in the allocation formula. This approach ensures that flat glass sites will be adequately covered despite the potential distortion of the necessary maintenance periods. Additionally, this approach will also help protect the industry in the beginning few years of the program against the lingering impacts from the severe economic downturn by allowing the year that was most heavily impacted by it to be dropped from the average. This averaging method, in which the high and low years of the five are dropped, is the basis for the flat glass industry allocations in the European Union and has been found to be a reasonable and fair approach for that program. GANA appreciates staff's consideration for the longer output averaging period currently in the draft regulation but in order to further protect against leakage within the glass industry, GANA urges a further refinement of the method: using a five-year look-back period with a provision to factor out years impacted by heat-up periods and hot holds. (GANA)

Response: We added a "true-up" term ($O_{a,trueup}$) for adjusted outputs not properly accounted for in prior years' allocations in the equation for calculating allocations under section 95891. We believe this addresses the commenter's concern.

Production Stoppages

C-74. Comment: Ensure that container glass facilities with production stoppages (e.g., due to a cold repair) are not penalized using the "recent output" formula input. CARB has attempted to address this potential unfairness in the definition of "output." which states: "If three years of data are unavailable the Executive Officer may employ a shorter time period to calculate the annual average." CARB should clarify, however, that periods of suspended operation, including the diminished production levels following such suspensions, will not reduce the allocation of GHG allowances in following years as production returns to meet market demands. (SMITHS)

Response: We added a "true-up" term ($O_{a,trueup}$) for adjusted outputs not properly accounted for in prior years' allocations in the equation for calculating allocations under section 95891. We believe this modification, together with the annual updating of product outputs, adequately addresses production fluctuations.

Consider Different Technologies

C-75. Comment: Early discussions with CARB staff indicate a preference regarding glass melting furnace design and operation which essentially results in remedy selection. The concerning issue is that it appears that staff has limited understanding of the glass manufacturing process and the total energy requirements associated with different furnace designs and combustion technologies.

Staff should not determine remedy in a cap and trade scenario where the intent is to drive new technologies forward. Likewise staff should not determine the industry winners and losers due to a narrow focus on a portion of a process's GHG emission rather than the collective GHG footprint associated with the entire process. In some cases this may require the inclusion of indirect GHG emissions associated with electrical consumption or a bifurcation of glass manufacturing sector technologies.

The apparent preference of staff to oxy-fueled furnaces as opposed to regenerative furnaces is a poignant example. Although oxy-fueled furnaces will demonstrate a slightly lesser GHG emission footprint in direct emissions due to a lower fossil fuel combustion rate in comparison to a regenerative furnace, once the indirect GHG emissions associated with the electricity requirements for the production of oxygen is included with the direct emissions of each type of furnace the GHG emission gap is at a minimum eliminated.

CARB staff must take into consideration the need to bifurcate certain industry sector technologies to assure that an inadvertent unfair advantage is not provided to certain manufacturing companies and/or technologies. (OWENSIL)

Response: We developed a separate benchmark for container, flat, and fiber glass manufacturing, and the results are presented in Table 9-1 of Section 95891(b). We believe that the focus of benchmarking under the cap-and-trade program is to create the correct incentives for GHG reduction while preventing leakage. This means that, in most cases, it is appropriate to avoid benchmarks differentiated by technology, fuel mix, size and age of the facility, climate circumstances, or raw material.

Product Weight

C-76. Comment: Additional protection is necessary to protect the capacity of regulated sources rather than simply focusing on their actual emissions. Under the federal New Source Review program as well as California's State Implementation Plan, the analysis of a source's historical production is evaluated by accounting for the level of production that the source was capable of accommodating. See, e.g., 40 CFR section 52.21(b)(41)(ii)(c) (the "demand growth exclusion"). Thus, if a customer seeks a lighter bottle that requires less material, which thereby reduces the container glass furnace's glass pull rate, the source is not punished for making that lighter and more environmentally friendly product. By contrast, without a similar provision in the proposed Cap and Trade Program, a purely output-based calculation of GHG allowances would create a perverse disincentive for every manufacturer to avoid producing lighter products because, by doing so, that company would effectively forfeit payment of its ability to return to a heavier product afterward. (SMITHS)

Response: By reducing the amount of material used per bottle, a facility furnace can produce more bottles based on a constant glass pull rate. If this additional capacity is realized in the production side of a facility, this allows the facility to sell more bottles. Even though allocation is based on glass pulled, a facility will have the opportunity to sell more light bottles with the same emissions and allocation. That is a direct incentive from the cap-and-trade program to create lighter bottles. In addition, benchmarking on a per bottle basis poses data challenges requiring different benchmarks based on size and weight.

Hydrogen

C-77. Comment: In order to insure equitable treatment of all market participants, third-party owned/operated hydrogen production facilities must be included in benchmarking determination and the allowance allocations. (APC)

Response: We developed a separate benchmark for hydrogen gas based on the amount of hydrogen gas produced. The benchmark is presented in Table 9-1 in section 95891(b).

C-78. Comment: The principle objective of the benchmarking process should be to insure equitable treatment of all sector participants through methodology that appropriately reflects the emission performance relative to production output. The benchmarking method must provide both an accurate relative ranking, and an absolute (emissions per unit of production) measure for all sub-processes within the sector—specifically, petroleum refining and hydrogen production, including third-party hydrogen production. It is not possible to provide equivalent and equitable treatment of both captive and third party hydrogen plants using the "output barrel approach" as the emissions associated with captive hydrogen plants will not be differentiated from total refinery emissions and there are no "output barrels" directly associated with third-party hydrogen plants. (APC)

> **Response:** We recognize that equity issues exist between allocation to third-party production of hydrogen gas sold to petroleum refiners and refinery-owned hydrogen production. We believe that employing the CO_2 Weighted Tonne (CWT) approach for the refining sector is the best way to address this issue. We present a separate benchmark for hydrogen gas based on the amount of hydrogen gas produced in Table 9-1 in section 95891(b). This value will be used to allocate to third-party hydrogen facilities. It is derived from the hydrogen CWT function and is identical to the value that would be applied to refinery-owned hydrogen production under the CWT approach.

C-79. Comment: If an interim method would be necessary for the first compliance period, it still needs to be a method that maintains the equitable treatment of third-party hydrogen producers. We recommend that CARB adopt the absolute benchmark value (in tonnes CO_2-e/tonne hydrogen produced) that is being adopted as the EU ETS Phase 3 hydrogen benchmark and apply this benchmark as the basis for allowance allocations directly to the third-party hydrogen producers. (APC)

> **Response:** We agree. The Phase 3 EU ETS hydrogen gas benchmark is based on the CWT approach. We modified the hydrogen gas benchmark in Table 9-1 to align with this value.

Paper Industry

C-80. Comment: Facilities in California are typically already using a combination of natural gas as fuel and combined heat and power technology, and therefore, are already high performers from a GHG perspective. Under a sector averaging approach, the extremely low number of facilities that would comprise the benchmark in California—three paper manufacturers and two paperboard mills—would make it impossible to develop a reliable statistical measure of GHG performance. (AFPA)

> **Response:** We agreed that, from a statistical point of view, averaging data from three or two facilities has limitations. However, in developing benchmarks for industries with a low number of facilities in California, we analyzed different data

sets, including national data, to check the appropriateness of the benchmarks. From the perspective of the equitable distribution of free allowances to California facilities to minimize leakage risk, we believe that it is appropriate to use California facility data.

C-81. Comment: As we communicated in our January 2010 comments to CARB, AF&PA strongly supports the use of actual emissions as the basis for allowance allocations. The use of benchmarks, in particular, product-based benchmarks, as the basis for allocation is unworkable for several manufacturing sectors, including paper and paperboard, and arbitrarily creates winners and losers.

Unlike the cement and steel industries, most manufacturers, including the forest products industry, have large variation in products and processes. Due to this large variation, dissimilar products and processes would be placed in the same sector category under this approach. This results in a completely unrepresentative benchmark which will, in turn, over-allocate allowances to some facilities and under allocate allowances to others in a manner that is not based on their comparable efficiencies.

The industry has conducted an internal analysis of the allowance allocation method included in federal cap and trade legislation proposed earlier this year i.e.; sector GHG efficiency average by six-digit NAICS product code. This analysis of pulp and paper manufacturing, including the paper and paperboard sectors, showed no correlation between greenhouse gas emissions and product type. As a result, the distribution of allowances differs so significantly across facilities that it can be viewed as market distorting versus a reasonable “reward for early action” or a “correct incentive to produce a given product in the cleanest way (lowest emitting way) possible,” (page J-21) as intended. For example, the distribution of annual costs borne by an individual facility within a NAICS code ranged from an expense of $15 to $20 million (at a $20 allowance price) for some mills to $9 million in revenue for others. The magnitude of such costs will force facilities to close rather than invest in efficiency improvements. The application of such benchmarks in a regulatory setting is inappropriate. Furthermore, excessive spending to purchase allowances only serves to drain resources that could have been spent on capital improvements to reduce GHG emissions.

Rather than product type, our analysis shows that fuel type, and degree of integration and steam production, are the overriding factors that determine a facility’s greenhouse gases. In most cases, these factors are intrinsic to a facility’s operations and cannot be changed without changing the basic nature and/or configuration of the facility. For example, it would be unreasonable to expect a non-integrated paper or paperboard mill using natural gas, similar to those in California, to alter its operations so extensively as to begin producing, rather than purchasing, pulp (i.e., become integrated) and use biomass fuel. Any benchmarks developed for regulatory purposes should take these factors into account. (AFPA)

Response: We disagree with the commenter's approach taken to analyze the paper industry and used a different approach in our analysis. In our analysis, we disaggregated each of the products from each of the six-digit NAICS codes. We analyzed three different product types under NAICS code 322130 and one product type under 322121. Under these subcategories, we found a relationship between greenhouse gas emissions and production, and produced benchmarks accordingly. These benchmarks are found in Table 9-1 of sections 95891.

C-82. Comment: The European Union has developed GHG benchmarks for industry allowance allocation under its Emissions Trading Scheme. It should not be assumed that such benchmarks are applicable to U.S. operations. As policymakers work toward an international climate agreement, a global carbon market, and examine comparable actions by trading partners, it will become evident that many U.S. manufacturing sectors are less energy efficient than their international competitors. Due to poor economic health, historically lower energy costs, and high capital costs required to make investments in alternative fuels and energy efficiency, the U.S. Forest Products Industry GHG profile does not compare favorably against some of its international competitors, both in developed countries and in emerging economies where state of the art facilities are being built, frequently with government subsidies. International benchmarks used as the basis for sector crediting in developing countries or border adjustments will only serve to put many U.S. manufacturers at a competitive disadvantage and eventually out of business with a corresponding loss of hundreds/thousands of jobs. (AFPA)

Response: We disagree and do not believe it is necessary to add provisions to the regulation to modify benchmarking stringency. We believe that benchmark stringency should reflect the emissions intensity of highly efficient, low-emitting facilities within each sector. We believe the benchmark stringency we have selected will minimize leakage in the forest products sector.

Refineries / Oil & Gas

C-83. Comment: The criteria for determining which benchmark to use for the refining sector, is not specified. Nor is it fully understood how each of the options would impact WIRA members. (PMTPETRO1, WIRA1)

Response: Per Board Resolution 10-42, we finalized the allowance allocation system, including benchmarks for allocation to industrial sectors, prior to the start of the first compliance period in 2013. Benchmarking for the refining sector was completed in the second 15-day changes to the regulation.

Support

C-84. Comment: WSPA concurs that the upstream oil and gas sector is highly trade exposed and should receive an assistance factor of 1.0 for all three compliance periods. We recognize the benchmarking methodology for the upstream sector in the staff proposal as a credible first step. (WSPA1, WSPA2)

Response: No response necessary.

C-85. Comment: We share ARB staff's desire to ensure that the final refining benchmark is based on energy efficiency and that the final thermal and non-thermal differentiated upstream benchmark is completed from validated data. (CHEVRON1, CHEVRON3)

Response: No response necessary.

Use Best Practices

C-86. Comment: Any free allocations based on production should be based on the most efficient refinery and not reward refineries with higher GHG emissions due to the type of crude refined or their configuration. Benchmarks for any free allocations should be based on the type of intermediate or final product produced and whether the process begins with an unrefined or a partially refined intermediary product, and updated based on best practices similar to Best Available Control Technology for criteria pollutants. (ICCT1, ICCT2)

Response: Benchmarking is used as a tool in a cap-and trade program to compare GHG performance across similar industrial sectors. Our process in product benchmarking includes selecting appropriate products, examining emissions and expected carbon costs, and determining benchmark stringency. The operational specificities, hence energy requirements, for the production of the types of products are taken into account in developing the benchmarks. The goal of our approach is to provide flexibility for the affected facilities to comply, as well as incentives for technology innovation. Best practices, technology forcing, or best available technology benchmarks are in essence benchmark stringencies, frequently used in setting emissions standards. In a market-based program such as cap-and-trade, the goal of benchmarking is to allocate free allowances to assist facilities with the cost of compliance, to prevent leakage and to incentivize them to reduce GHG emissions. We set the product benchmarks to reflect the emission intensity of highly efficient, low-emitting facilities within each sector. We believe that our method and design will provide effective incentives for the affected industries to reduce emissions and stay operating in California.

Baseline Emissions

C-87. Comment: Our Coker Modification project, completed in 2008, has resulted in reduced CO_2 emissions of an estimated 462,000 tonnes/yr. In response to our request for "Early Action Credit" for this project CARB's letter of April 10, 2010, stated that the project would "save Tesoro millions of dollars per year in the form of either a reduced need to purchase allowances at auction or in the form of allowances given for free." While the WSPA proposed tempered Ell methodology may result in realizing these savings, appropriate setting of the baseline years as allowed in the regulation will ensure our investment is recognized; specifically, the historical baseline for emissions must be based upon the most representative certified data from the time period 2006-2010. We also request that ARB consider a specific treatment of this project if it becomes impossible to adequately address this issue within the scope of the allocation method. (TESORO)

Response: Our benchmark-based allocation system recognizes and encourages early action. Benchmarks are chosen to reward facilities who have historically chosen to employ low-GHG fuels and enhance their emission efficiencies of their production process. As stated, the Coker Modification project's reduction in CO_2 emissions would "save Tesoro millions of dollars per year in the form of either a reduced need to purchase allowances at auction or in the form of allowances given for free" under our cap-and-trade program.

C-88. Comment: The historical baseline emissions for refineries should be based upon the most representative certified data from the time period 2006-2010 using defined criteria. Quantities for 2013 and 2014 would be this same amount but adjusted by the cap adjustment factor. (WSPA1, WSPA2)

Response: We use an average of the three most current years of product output and emissions data in developing the simple barrel product benchmark. The data sources considered include ARB Mandatory GHG Reporting, ARB industry surveys, U.S EPA Mandatory Reporting, California Energy Commission fuel production data, European Union Emission Trading Scheme Studies, academic literature, and stakeholder-provided data. The first-period allocation to individual refineries offers flexibility to use 2006-2010 data in establishing representative emissions baselines.

Small Refineries

C-89. (multiple comments)
Comment: Cap and trade should be designed to encourage the manufacture of products to reward processes that use the least energy per unit of output. In refining, the more complex the refinery, the greater the greenhouse gas emissions needed to make a gallon of transportation fuel. WIRA member refineries are simple operations that have historically made it more difficult for them to meet your specifications. Here, however, the carbon emission WIRA members generate to make transportation fuels are less than the greenhouse gas emissions the big oil companies generated to make a gallon of transportation fuel. The allocations system should not ignore and disadvantage the efficiencies of the small and less complex WIRA members, and we'll continue to work with your staff to ensure the proper outcome. (WIRA2)

Comment: Full recognition of more efficient, less complex refiners by utilizing the simple barrel output method across the full slate of products. Efficiencies should not be averaged nor reduced in a manner that disadvantages small, less complex facilities to larger, more complex facilities. An energy intensity index approach may represent similar results; however, any manipulation within the index could disadvantage more efficient refiners. Kern is concerned that future efficiency reductions should not be weighted in a manner that rewards prospective efficiency over existing efficiency. It is clear that reductions from an inefficient facility will be easier and less costly to achieve than reductions from a facility that is already incurring costs to operate more efficiently. (KERNOIL1)

Comment: The larger and more complex the refinery, the greater the GHG emissions are per gallon of produced transportation fuel. This fact of the refining industry needs to be recognized specifically within the regulation. Currently, small and large refiners are categorized the same throughout the regulation. Staff should provide separate tiers within the regulation. This disaggregation would allow for a more tailored approach on the various aspects of the program, including benchmarking and leakage analysis. (WIRA1)

Comment: The regulation, as proposed, does not make a distinction between large complex refineries and smaller simpler refining operations of the type owned and operated by Paramount. Small, non-complex refineries are dramatically different from the larger complex refineries of major oil companies, and this difference needs to be acknowledged within the Regulation. With some relatively minor changes, the Board can alter the proposed program to acknowledge the distinction between large and small refineries, and recognize that small refineries actually produce transportation fuels with the lowest greenhouse gas profile available. Choosing a specific benchmarking metric at this point, without further analysis, could put independent refiners at a disadvantage in the market. In addition, since these small refiners survive on very thin margins which are often non-existent (unlike the majors, who make money on the production and marketing side of the business), so one mistake in CARB's regulatory program can lead to the quick demise of the few small refiners remaining in California. The larger and more complex the refinery, the greater the GHG emissions per gallon of transportation fuel produced. Currently, small and large refiners are categorized the same throughout the Regulation. Staff should provide separate tiers within the Regulation or find other ways to distinguish between large and small refiners. This disaggregation would allow for a more tailored approach on the various aspects of the program, including benchmarking and leakage analysis. (PMTPETRO1)

> **Response:** As stated in Appendix J of the Staff Report, we recognize the differences between simple and complex refineries. Our first-period allocation to refineries explicitly recognizes this difference by creating a category for complex facilities (those with a Solomon Energy Intensity Index value) and simple refiners (those without a Solomon Energy Intensity Index value). The CO_2 weighted tonne (CWT) approach that will be used beginning in the second compliance period is designed to account for the complexity of each facility and creates an equitable balance between simple and complex facilities.

Sector Allocation

C-90. Comment: Starting in the second compliance period, the free allowance quantity for the sector would vary according to the throughput-based benchmark calculation proposed in the regulation (see section 95891). The basis for the benchmark would be one that reflects refinery complexity. (WSPA1, WSPA2)

> **Response:** We agree. In the first compliance period, we use the simple barrel benchmark to determine an initial aggregate number of allowances available for the refining sector. Because of the complex nature of the refinery process (i.e., input, output, and configuration all impact emissions), the simple barrel approach to benchmark refineries has some limitations when used to allocate to individual facilities. To address this issue we developed an approach based on the Solomon Energy Intensity Index for complex facilities in the first compliance period. In the second and third compliance period, we use the CWT approach, which is a throughput-based benchmark that reflects refinery complexity.

Alternative Approaches

C-91. (multiple comments)
Comment: We have worked diligently with other WSPA members in the development of the tempered Ell approach to allocation for the first compliance period and are encouraged by your mention of this approach in the proposed regulation. Our internal work has shown the CWT methodology adopted in Europe is inadequate in terms of recognizing and rewarding improvements in processing technology or efficiency and that it exaggerates the carbon intensity differences between refineries relative to realistic opportunities to reduce carbon intensity. The tempered Ell approach allows a measured approach towards benchmarking for the first compliance period while developing a more comprehensive approach for the future. (TESORO)

Comment: For the first compliance period, WSPA proposes a tempered Energy Intensity Index (EII) methodology for refineries that would allocate direct free allowances based on a facility's Solomon EII metric and emissions, compared to the other sector facilities and the sector total emissions. WSPA has suggested that for the second and third compliance periods, a comprehensive, complexity-weighted methodology (yet to be developed) would be used to establish a benchmark and a basis for distribution of free allowances. (WSPA, WSPA2)

Comment: The Solomon Energy Intensity Index (EII) approach provides a better relative ranking of petroleum refining activities, but the fact that it solely considers energy consumption and does not effectively consider process emissions, the EII method does not reduce to an effective absolute measure (emissions per unit of production) as a benchmark. Further, since process emissions make up the predominant fraction of total GHG emissions from hydrogen production, this method will be particularly unfair for third-party hydrogen production. In order to establish a relationship between EII and GHG emissions, CARB will have to be very careful to separate refineries that produce hydrogen from those that purchase hydrogen—or include an allocation of the appropriate third-party energy consumption and GHG emissions associated with imported hydrogen dedicated to each refinery in the benchmarking analysis. (APC)

Comment: The actual energy efficiency difference between the most efficient refinery and the least efficient refinery is only 15 to 20 percent. Therefore, the benchmarking scheme used should not vary in the amount of coverage of emissions that are given out as free allowances by more than 15 to 20 percent. This percentage should be applied to the required percent reduction. For example, if the industry as a whole had to reduce emissions by 10 percent, then the difference between the percent allowances between the best in class and the worst in class should not be more than 15 to 20 percent of 10 percent or 1.5 to 2.0 percent (i.e., best gets 92 percent of required allowances and worst gets 88 percent). If the absolute percentage of 15 or 20 percent were used, then the best would get 110 percent and the worst would get only 70 percent of allowances needed. Clearly the best in class refinery cannot be three times more energy efficient than the worst, but that is the magnitude of the reduction required or allowances that need to be purchased if benchmarking is not applied fairly. The benchmarking issue has the potential to pick winners and losers and must be carefully developed and applied. (VALERO)

Comment: Create a refinery benchmarking process that does not reward or penalize individual refineries. CARB is proposing that allowances be distributed within the refining sector in part based on energy efficiency benchmarking (see section 95891(b)). The use of the Solomon Energy Intensity Index (Ell) has been suggested as a potential tool, but with the critical caveat that it include "tempering" to soften the competitive differences between more efficient refineries and less efficient refineries. We have two concerns. First, as proposed, benchmarking would begin immediately in January 2012. The additional and immediate competitive costs borne by some refiners would make them less competitive at a time when investments in energy efficiency are needed. Refineries should not be rewarded or penalized in the issuance of allowances based on current energy efficiency. Improvements in energy efficiency may be possible, but projects that would have significant impact (e.g. cogeneration units) would take up to four years to engineer, fund, construct and place in operation. Second, the Solomon Ell metric has traditionally been used as a relative indicator of energy efficiency versus peers. It was not envisioned or designed for any financial use. It is a theoretical tool, and is highly dependent on the user's data and assumptions. While the Ell has a correlation with GHG emissions, it is not precise in that it excludes significant process emissions of carbon dioxide from hydrogen plant operations and other sources. Lower refinery utilization (throughput) can significantly increase Ell without any changes to the facility. Solomon has also updated the tool in recent years, which can make year-to-year comparisons challenging. It is an imperfect tool for distribution of allowances to the refining sector. We recommend deferring benchmarking to 2015 to avoid immediate competitive impacts that would start in January 2012. Energy costs and the cap-and trade system will provide immediate incentive for energy efficiency improvement. If Solomon Ell or surrogate is selected as the benchmarking metric for refinery energy efficiency, the use of it should include significant phase-in and "tempering." This tempering would be a simple smoothing of the mathematical application of Ell to reduce the current and immediate competitive differences between various refineries. CARB should work with our industry to develop the best tool for greenhouse gas benchmarking for use as soon as possible and no later than 2015, incorporating best practices from the European system. (CONOCO)

Comment: We recommend employing the Carbon Weighted Barrel (CWB) approach as the benchmarking method for the Petroleum Product Manufacturing sector. Since the methodology distinguishes between the emissions resulting from each discrete processing step, it allows for a benchmark for hydrogen production to be defined which is representative of all production processes and producers. Therefore, this method allows for equitable allocation treatment of both captive and third-party hydrogen production. CARB would benefit from building directly on the work of the EU ETS Phase 3 program development. (APC)

Comment: More analysis of the refining sector is needed. Staff has acknowledged in the Staff Report and in recent meetings that many technical details still need to be analyzed with respect to the allocation distribution formula. It is currently unclear exactly how each of the benchmarking options proposed will affect WIRA members. A fuller understanding of CARB proposals is needed before a conclusion can be reached. WIRA is committed to working with CARB staff to resolve these technical issues and requests that the Board direct staff to continue these discussions with industry. Choosing a specific benchmarking metric at this point, without further analysis, could put independent refiners at a disadvantage in the market. (WIRA1)

> **Response:** We analyzed a wide variety of proposals for refinery benchmarking. Our approach is outlined in Appendix A to the second 15-day changes to the regulation. The first compliance period approach is based on the simple barrel benchmark for the simple facilities and the Solomon EII approach for the complex facilities. This approach includes the “tempering” requested by stakeholders to address transition risk. The second compliance period employs the CWT approach, which is a throughput-based benchmark that reflects refinery complexity. This approach is very similar to the Carbon Weighted Barrel (CWB) approach recommended by some stakeholders.

First Compliance Period

C-92. Comment: WSPA recommends that the free allowance quantity for the refinery sector be fixed for the first compliance period. For 2012, the free allowance quantity should be set at 100 percent of historical baseline emissions for the sector. Any baseline determination should recognize significant refinery expansion and configuration changes. (WSPA1, WSPA2)

> **Response:** The first compliance period starts in 2013; this is a change noticed in the first 15-day changes to the regulation. No free allowances will be given in

2012. The total amount initially allocated to the refining sector will be set based on the simple barrel benchmark for the first compliance period. The amount allocated to individual facilities will recognize expansion and configuration changes through the true-ups built in to the allocation approaches for all compliance periods.

Allocation to Oil and Gas for Electricity Use

C-93. Comment: Because upstream oil and gas operations are highly trade exposed, we propose that the sector receive the allowances for indirect electricity use directly, as opposed to the provision of giving those allowances to the distributors. Currently, the draft rule proposes that industrial customers receive energy efficiency programs or other indirect assistance instead of the direct rebates required to address carbon cost impacts on consumers and commercial sectors. Direct allowance distribution to the sector will more fairly address the impacts of higher energy costs that would otherwise disadvantage this highly trade exposed sector. These allowances for imported electricity can be deducted from the utility sector to prevent double counting. (WSPA1, WSPA2)

Response: We do not believe it is necessary to add provisions to the regulation to include indirect emissions associated with electricity at this time. In the program framework, an adjustment factor was not made for power purchased in establishing the product-based benchmarks. This is because purchased power may not create an indirect carbon cost in all California utility service territories. It is ARB's goal to see a carbon price properly embedded in all utility rates. If and when this occurs, the compensation for these indirect carbon costs could be incorporated into the product benchmarks (or reductions in these costs created in some other fashion) to help minimize leakage. We will revisit this issue once the California Public Utilities Commission Proceeding addressing utility costs and revenue issues associated with greenhouse gas emissions concludes.

Associated Gas with Oil Production

C-94. (multiple comments)
Comment: The draft rule may not clearly address associated gas with its level of GHG emissions. Associated gas requires considerable compression (i.e., electricity) along with gas treatment etc. If the associated gas is not included correctly along with the barrels of oil, the calculation will be in error. We will work with ARB staff to develop the correct method to benchmark for associated gas with oil production. (WSPA1) (WSPA2)

Comment: An additional NAICS code (211112) needs to be added to oil and gas extraction sector in table 9-1 on A-80. Product output could be a barrel of natural gas liquids by natural gas extraction. The point of regulation should be tied to the point of collection for the "position holder" definition used in the excise tax laws. If the proposed regulation is not harmonized with the excise tax proposed regulation, issues could arise in the context of fuel sold via an exchange agreement (2-3 party exchanges), in-tank transfers, or terminal product purchase agreement. (WSPA1, WSPA2)

> **Response:** The production of associated gas is accounted for in the oil extraction benchmarks. To accomplish this, we convert gas extracted into "barrels of oil equivalent" and use this as the metric for these benchmarks. We modified the regulation to include NAICS Code 211112. The benchmark for natural gas liquid production was included in Table 9-1 of section 95891(b).

Reduce Cap Adjustment Factor

C-95. Comment: Occidental concurs that the upstream oil and gas sector is an Energy-Intensive Trade-Exposed ("EITE") sector and should receive an Assistance Factor of 1.0 for all compliance periods. Without such EITE classification, inclusion of the upstream sector in a cap and trade program will create a disadvantage for California oil and gas production facilities relative to out-of-state (or out-of-country) competitors that do not face similar requirements. A final benchmarking approach must embody this complexity, which the single benchmark for non-thermal operations does not capture. There are many important factors that would allow appropriate definition of the non-thermal category and benchmark(s): Maturity of production operations; The use of non-thermal enhanced recovery methods; Special operating conditions; The extent of gas production and processing; The type of downhole fluid lifting technology used; The degree to which other operations at a facility are integrated with oil production operations; The GHG emissions profile for a facility's electricity. A benchmarking approach that does not consider these factors would significantly disadvantage certain upstream producers. It is imperative that the final methodology incorporate all relevant factors to allow for fair and equitable treatment of upstream operators. Occidental strongly urges the inclusion of a mechanism to reduce the initial rate of decline in the Cap Adjustment Factor for the upstream sector to avoid undue burdens on the competitiveness of affected California operations. (OPC)

> **Response:** We remain concerned about differentiating product benchmarks by process type or technology. Our goal is to remain neutral to technology choice to allow for choices that reduce greenhouse gases. For example, in the first 15-day changes to the regulation, we considered the use of the American Petroleum Institute's gravity metric (API gravity) to differentiate products in the oil production sector. This method resulted in two benchmarks, one for the production of heavy crude oil and one for production of light crude oil. This approach would have been more consistent with our "one product one benchmark" principle than an approach with a multitude of process technology-based benchmarks. However, in response to industry's comments on the first 15-day changes to the regulation, we reverted to the thermal and non-thermal framework for the second 15-day changes to the regulation due to concerns about heavily disadvantaging the extraction of light crude oil using thermal methods.

Soda Ash

C-96. Comment: Modify Appendix J, table J-4 as follows:
(1) NAICS Code 212391 has an ARB Classification of Soda Ash Mining and Manufacturing. The more appropriate classification would be: Potash, Soda and Borate Mining and Manufacturing.
(2) D.l.f.v. Product-Based Benchmarking: Soda Ash Mining and Manufacturing (NAICS 212391) I General Stationary Fuel Combustion Sources (Subpart C). The operation at Searles Lake referenced in this section produces multiple soda and borate products, previously produced potash and has the ability to produce potash in the future. The final paragraph in this section states that staff proposes using tons of soda ash produced as the output metric for this sector. A more representative metric would either be tons of product produced or tons of potash, soda and borate product produced. (SVM)

> **Response:** We modified our regulation to include NAICS Code 212391 in Table 9-1 of Section 95891. This code is defined as Potash, Soda, and Borate Mineral Mining, with a benchmark of 0.948 short ton of soda ash equivalent.

Solar Turbines

C-97. Comment: The proposed benchmarking approaches, and Allocation Assistance Factors for the purposes of emission allocations, do not appear to be appropriate for Solar's operations or products. The Industry Assistance Factor presented in Table J-3 and benchmarking process should be developed uniquely for Solar since we are the only operation in our industry classification and should reflect our limited ability to switch to lower carbon strategies. The regulation should not be adopted for our industry sector until the benchmarks are completed and verified. (SOLARTURBINES1, SOLARTURBINES2)

> **Response:** We modified our regulation to include NAICS Code 333611 in Table 9-1 of Section 95891. Under this NAICS code, we have added a benchmark for testing of turbines and turbine generator sets.

Leakage

General Concerns about Leakage

C-98. (multiple comments)
Comment: Please do not go forward with this. This is a recipe for disaster for all of California. Why should people or companies pay to pollute the air and then every company that can't afford to pay will end up leaving this state and then where does that leave us? (CMWEBER)

Comment: The state of CA does not need Cap and Trade. What we need is a government that will create jobs not additional taxes or ways to have business leave this state. Additional regulation will drive businesses out of the state. No on Cap and Trade. (PENCE)

Comment: We already have some of the strictest environmental laws in the country. Arizona is just miles away - please don't force us there or to Texas. We want to stay here. (LYNES)

Comment: Please no more regulations. Please do away with Cap and Trade. We need jobs in California not more questionable environmental regulations. What good are these regulations when industry just leaves the state and the country? (ROTH)

Comment: California cannot afford this program. By imposing these rules on California we will simply export more jobs the people who are doing the most pollution. (HERNDON)

Comment: I am opposed to the implementation of AB 32. I believe it will cause many, many companies to leave this state. As for the ones that you say will be "created" ie green jobs, this will only occur if the subsidies continue. With the current state of the Federal, State, and local budgets, I think this is improbable. Of course, you can always mandate that folks buy green products through your rulings. If this is the case, I, for one will leave the State as soon as possible. (COOKINHAM)

Comment: I am troubled with the go-it-alone approach of California in this and without consideration to the surrounding states. And I was impressed with Dr. Hanemann's remarks this morning that there has been inadequate attention to the leakage with regards to the surrounding states. I would strongly encourage you to give more attention to those impacts on our economic development. (SACHISPCHMBR)

> **Response:** We share your concerns that if energy-intensive trade-exposed (EITE) industries are not appropriately compensated, the program has the potential to create disadvantages for California facilities relative to out-of-state competitors that currently do not face similar requirements. If production shifts outside of California to a region not subject to GHG emissions-reduction requirements, emissions could remain unchanged or even increase. This is referred to as emissions “leakage.” AB 32 requires ARB to design measures to minimize leakage to the extent feasible, and the cap-and-trade program is designed to minimize leakage in several ways, including accounting for out-of-state and in-state electricity generation and by linking with partner jurisdictions in the Western Climate Initiative (WCI). ARB’s allocation approach is also intended to minimize emissions leakage for those in the industrial sector.
>
> We analyzed the potential for emissions leakage by looking at emissions intensity and trade exposure. “Emissions intensity” is a measure of the impact that carbon pricing will have relative to a sector’s economic output. Those with higher emissions per unit of output are considered to be more emissions intensive. “Trade exposure” is a measure of a sector’s ability to pass through a

cost. Without assistance, industries that are both highly emissions-intensive and trade-exposed have the potential to be negatively affected relative to competitors that do not face similar GHG emission reduction requirements. To minimize the potential for leakage, the program relies heavily on free allocation in the program's early years.

We believe that free allocation to industrial entities at risk of emissions leakage will help maintain the competitiveness of California industries. For as long as ARB assesses that the risk of leakage persists, allowances will be allocated for free to those at risk. We will monitor leakage and will report to our Board annually on shifts in business activity that may result in emissions leakage and changes in market share for covered entities and sectors**,** and will evaluate industries for changes in leakage prior to second and third compliance periods.

General Support for Addressing Leakage through Allocation

C-99. (multiple comments)
Comment: We support a modest amount of free distribution of allowances to a carefully considered subset of trade-exposed industries, subject to periodic review. (UCS3)

Comment: If the State of California proceeds to adopt a Cap and Trade program, such a program should be fair and not cause leakage. (SMITHS)

Comment: Free allocations are needed to provide an effective transition and protect against carbon leakage. (APC)

Comment: It's important to aid highly exposed, leakage prone industries through the free allocation of allowances, requiring medium or low leakage prone industries to purchase allowances in an auction in the second and third compliance periods will unnecessarily increase the cost of compliance for businesses. As long as California chooses to "go it alone" on cap and trade, the risk of leakage will remain high. CARB should take every step possible to avoid this scenario. (CALCHAMBER1)

Response: We agree that preventing leakage is important, and we designed our allocation system to prevent leakage. We determined which covered entities are at risk of leakage after analyzing available data on emissions intensity, trade exposure, or cost pass-through ability, as well as approaches used by other organizations. Per Resolution 10-42, we will update the Board annually on the status of the cap-and-trade program implementation, including, to the extent feasible, information on shifts in business activity that may result in emissions leakage and changes in market share for covered entities and sectors.

Adaptive Management for Allowance Allocation

C-100. (multiple comments)
Comment: A clear adaptive management process should be outlined in the regulations to evaluate and adjust the Industry Assistance Factors in Table 8-1 of the regulations so that the percentages do not necessarily remain static through 2020. (NC2)

Comment: Build in an adaptive management process to assess the impact of free allocation on industries and leakage over time and adjust free allocation as needed. (UCS1, WALTERS, LUDLOW)

Comment: CARB should build in an explicit adaptive management process to adjust the free allocation to the industrial sector based on specified evaluation metrics. (TAYLORE)

Comment: The proposed approach appears to offer no dynamic, adaptive response in the event of sustained oversupply other than to stockpile unsold allowances in the allowance reserve. Moreover, CARB has no plan for an ongoing assessment of whether free allocation results in windfall profits to particular sectors. Similarly, there is no means to adjust free allocation to the industrial sector in the event of a strong regional, national or international emissions cap (or similar policy) that reduces or eliminates the risk of leakage.

These concerns are magnified by in the absence of any requirement that allowance recipients document how the value of allowances is invested in lower-emitting, higher-efficiency processes or low-carbon sustainable fuels. This information needs to be identified as part of the rule-making process, not in retrospect after allowances are dealt out. This is particularly relevant to the second phase of the program. By 2014, when the allocation decision for Phase II must be made public, industrial and utility recipients of allowance value will have had ample opportunity to report on their use of allowance value.

If such information is not currently known to be available, then the onus should be on the receiving regulated entities to explain how their free allowance allocation will be used to prevent leakage and to transition their firm to be more competitive. (EDF1)

Comment: CARB should build in an explicit adaptive management process to adjust the free allocation to the industrial sector based on specified evaluation metrics. As a condition of free allocation, CARB should require industrial sector emitters to provide detailed information on production input costs and revenue to enable a more rigorous, analytical understanding of the extent to which free allocation protects consumers and prevents leakage, or to what extent allocation needs adjustment to avoid windfall profits. This information would be kept confidential at the individual firm level, though it could be released at the sector level so that proprietary information would not be compromised. After two years of data are collected, the ability to pass through costs would be assessed during the last year of the first compliance period. With this better understanding of the real importance of trade exposure and the risk of leakage, adjustments can be made for the second compliance period and going forward. (EBERHARD, KUSTIN10)

Comment: The current proposal lacks a schedule for reduction of free allocations, and there is no indication that CARB will phase out free allocations. The language remains vague in addressing any assessment methodology that will be used to evaluate at-risk sectors. Greenlining believes that a more specific and transparent assessment process must be developed before the first compliance period begins to effectively measure the need for free allocations.

Industrial sector emitters should be required to submit information on its production cost and revenues to ensure that free allocations do not result in windfall profits for these entities. To assess whether the free allocations are providing transitional assistance, CARB needs to also assess if entities are indeed using free allowances to invest in energy- efficiency or renewable sources. The information that entities provide will be confidential on an individual level, and be used to compose sector-wide analysis. Entities should be required to submit the information beginning in 2012, and CARB should provide an analysis that evaluates the sector's ability to pass through costs, and make adjustments to prevent leakage.

CARB's proposal stresses the considerable uncertainty in the industrial sector, and therefore it is crucial to develop a rigorous assessment methodology before the cap and trade program is implemented in 2012. It is regressive to give away free allocations to protect at-risk entities if consumers, especially low-income households and small businesses, will not be protected against the costs that entities are able to pass through. The best way to protect consumers is to carefully measure the need for free allowances and ensure that entities will not receive undeserved windfall profits. (GREENLINING1, GREENLINING2)

Comment: The regulation should also include monitoring procedures and an adaptive management process to assess the impact of free allocation on industries and leakage over time. (CPC1)

Comment: A clear adaptive management process should be outlined in the regulations to evaluate and adjust the Industry Assistance Factors in Table 8-1 of the regulations so that the percentages do not necessarily remain static through 2020. (NC1)

> **Response:** ARB will continue to monitor leakage during the implementation process. Should ARB identify that leakage is occurring, we will develop appropriate responses to rectify it. We have included features in the cap-and-trade regulation, such as periodic updating of leakage risks to adjust or phase out free allocations. We will work with the California Public Utilities Commission to ensure that the proposed allowance value directed to the electric distribution utilities is used for the benefit of residential, commercial, and industrial

ratepayers that might otherwise face indirect costs from implementation of this regulation, and for the purposes of AB 32.

As noted in the Staff Report, we are committed to monitoring how covered sectors, especially those that receive free allocation, address carbon costs once the program is in place. In addition, for allocation purposes, we are collecting product data from almost all sectors at risk for leakage. The data set from this collection will also serve as a key monitoring step in detecting leakage. During program implementation, we will assess whether it is necessary to collect such confidential business information as production input costs and product revenues to determine if businesses incur windfall profits as a result of free allocation. We anticipate that the combination of rigorous benchmark formulas and basing the free allocation on production data should ensure that free allocation for leakage purposes does not result in windfall profits or a sustained oversupply of free allowances.

Per Resolution 10-42, we will continue to review information concerning the emissions intensity and trade exposure of different industries in California. We will recommend changes to the Board on leakage risk determinations, if needed, prior to the initial allocation of allowances for the first compliance period starting in 2013 for industrial sectors not identified in Table 8-1 of the cap-and-trade regulation. And prior to the initial allocation of allowances for the second compliance period starting in 2015 for industries identified in Table 8-1 of the cap-and-trade regulation. We will update the Board annually on the status of the cap-and-trade program, including, to the extent feasible, information on shifts in business activity that may result in emissions leakage and changes in market share for covered entities and sectors.

C-101. Comment: As demonstrated in Appendix F, CARB's economic analysis does not evaluate the leakage impacts of AB 32 in any manner. This is a glaring omission that has been criticized by several policy experts and economists, including those on the Economic & Allocation Advisory Committee. In the absence of such analysis, CARB cannot confidently or convincingly state that its proposed approach is consistent with its mandate to minimize leakage to the extent feasible. (CSCME2)

Response: We do not agree. We detailed our leakage analysis in Appendix K of the Staff Report. The analysis included the mechanisms for addressing emissions leakage recommended by the Economic and Allocation Advisory Committee.

C-102. Comment: We support the language in Resolution 10-42, Attachment B, which takes a deeper look at leakage. And we're hopeful that the periodic review language will be increased beyond the once a compliance period to maybe monthly or so to truly evaluate the impacts this regulation could have on our industry. (ACC2)

Response: ARB will monitor the implementation of the cap-and-trade regulation as directed by the Board per Resolution 10-42. The details of our process for implementing the cap-and trade program, including leakage monitoring, are issues that will be developed before the start of compliance for the cap-and-trade program in 2013.

C-103. Comment: In its Statement of Reasons, CARB states that it will monitor the leakage situation and examine mechanisms such as a border adjustment or changes to the allowance distribution system should it find that leakage is occurring. However, CARB does not detail how it will conduct such monitoring. In addition, CARB does not incorporate any placeholder for such a program into the regulation itself. CSCME urges CARB to direct staff to develop a specific provision in the text of the proposed regulation or in a related rulemaking that develops an effective monitoring mechanism with specific triggers for the adjustment of the current approach to minimizing leakage in the event initial indicators show that leakage is occurring. It is critical that any monitoring mechanism provide for immediate intervention to respond to indications that leakage is occurring. (CSCME2)

Response: Details for monitoring leakage and mechanisms will be developed during implementation. For allocation purposes, we are collecting product data from almost all sectors at risk for leakage. The data set from this collection will be critical to detecting leakage. We will work with all interested parties to identify additional sources of information at the state level that could improve ARB's ability to monitor leakage. Should ARB find that leakage is occurring despite the safeguards in the regulation, ARB will examine mechanisms to address leakage, including border adjustments or changes to the allowance distribution methods in future amendments to the regulation.

C-104. Comment: Kern recommends that a mandatory review provision be included in the regulation. Leakage review should be conducted yearly while full review should be made at least every three years. (KERNOIL1)

Response: Per Resolution 10-42, we will update the Board annually on the status of the cap-and-trade program implementation, including, to the extent feasible, information on shifts in business activity that may result in emissions leakage and changes in market share for covered entities and sectors.

C-105. Comment: We recommend a mid-course update of the identification of sectors singled out for special treatment due to potential leakage. We support distributing free allowances only for the purpose of addressing emissions leakages associated with trade-exposed industries. However, CARB staff has noted that limitations on the availability of data and staff resources diminished the quality of the analysis that was performed to assess sectorial vulnerability. We recommend that CARB complete a reassessment of leakage risk by 2014 and specify how the protocol for special treatment of leakage would apply during 2015-2020. (UCS3)

Response: Per Resolution 10-42, we will, if needed, recommend changes to the Board on leakage risk determinations prior to the initial allocation of allowances for the second compliance period starting in 2015.

Cement

C-106. (multiple comments)
Comment: The resolution suggests that staff may be reconsidering the idea to allocate a hundred percent of allowances in the cement sector and I'd just like to caution against that. Auctioning should be our first priority allocation method absent some other evidence that leakage and trade exposure is a risk. In combating leakage for the cement industry the resolution suggests that we might be looking towards using some form of border adjustments to guard against leakage in that sector. We're supportive of making sure we have a level playing field to treat importers and in-state entities alike. I think the concern is to just to make sure that we don't use both border adjustments and pre-allowances to combat leakage in that sector. You can't really have it both ways. (NRDC3)

Comment: The regulation provides an inappropriately generous allowance allocation to the cement sector. EDF recommends CARB revisit the cement sector allocation and require firms receiving allowances to demonstrate how the value of those allowances is being used to avoid leakage. EDF recommends that CARB revisit this portion of the ISOR and provide additional justification for the leakage assistance given while taking into account the emerging trend of allowing for increased use of SCM blending in finished cementitious products used in roads and buildings throughout California and the western United States. (EDF1)

Comment: The persistent 100 percent assistance factor seems particularly inappropriate amidst claims by the cement industry that they are operated at state-of-the-art already. If that is the case, it is not at all clear how transition assistance will facilitate any transition. In putting forth this strong position on the cement sector allowance allocation, we observe that there is need to incentivize blended cement products, and to spur a transition from conventional fossil fuel-based power. The threat of this unintended possible consequence of a free allowance allocation is also exacerbated by the short 9-year program horizon. (EDF1)

Response: We believe our leakage risk classification of the cement sector is appropriate based on our analysis of available information. The cement sector has been classified as a sector with high emission intensity and medium trade exposure. We evaluated the feasibility of implementing border adjustments especially for the cement sector. However, at this point, we believe there are technical limitations and insufficient resources to implement such a border adjustment. Since border adjustment is not part of the program starting in 2012, free allocation is the primary mechanism to address transition and leakage risk. Per Resolution 10-42, we will keep evaluating the feasibility for border adjustment as part of future amendments to the regulation. As program implementation starts, we will monitor how the market participants will react. We will consider including reviews of emission reduction activities taken at covered facilities as part of monitoring.

We agree that increasing blending of substitutable cementitious materials (SCM) to cement is a viable emission-reduction option. We, not only as part of cap-and-trade, but also as part of other programs, will keep reviewing possible opportunities to incentivize increased blending. We note that the price signal in cap-and-trade should provide an incentive to increase blending of SCMs at the batch plant once the price signal is embedded in cement.

C-107. Comment: CARB ignores critical qualitative evidence in determining the trade exposure of the California cement industry, including nearly two decades of antidumping rulings. The California cement industry's extreme vulnerability to imports is evidenced by nearly two decades of antidumping rulings by the ITC. In support of these rulings, economists at the ITC analyze public and confidential firm-level data on price, market share, and profit. This is precisely the information that CARB would need to make a complete and accurate assessment of cost pass through ability. CARB should reclassify the California cement industry as "highly trade exposed." The weight of both quantitative and qualitative evidence conclusively demonstrates that the California cement industry has a high trade exposure, faces a high degree of competition from unregulated entities, and has extremely limited cost pass-through ability. CSCME recommends that CARB incorporate this evidence into its determination of the cement industry's trade exposure and place it within the "highly" trade exposure category. Although CARB has already designated the cement industry as "highly" leakage exposed, such a designation does not account for the fact that the cement industry's leakage risk is far beyond that of any other California industry's assessed risk. The combination of high trade intensity and high GHG intensity creates an extremely high risk of leakage for the California cement industry and justifies additional measures to minimize leakage in implementing AB 32. (CSCME2)

Response: As described in Resolution 10-42, we will continue to review information concerning trade exposure of different industries. The review focuses on identifying sectors not identified in section 95871 Table 8-1 of the regulation for inclusion prior to the initial allocation of allowances, and for adjusting allocations for sectors included in Table 8-1 for the second compliance period that will start in 2015. For the cement sector, we will continue to review trade-related information, including information from antidumping rulings by the International Trade Commission (ITC) as mentioned, to determine if the cement industry should be reclassified from medium to high trade exposure.

C-108. Comment: The major issue we face under a cap and trade program is our extremely high exposure to economic emission leakage, our extraordinarily high emission intensity exposure to the industry to compliance costs. And since cement is a globally fungible competitive commodity, we did not pass through the cost without losing market share to other alternatives. (CSCME3)

Response: We factored these concerns in calculating allowances for free allocation to the cement sector.

C-109. Comment: CSCME recommends the following modification to reduce leakage beyond levels achieved by the proposed regulation:

- Implement an incremental border adjustment that imposes obligations on imported cement that are comparable to those placed on domestic manufacturers;
- Revise the output factor so that allowance allocations and compliance obligations are based on the same level of output;
- Establish benchmarks based solely on the average GHG intensity of each industry or product;
- Allocate allowances directly to leakage-exposed industries to offset the costs associated with higher electricity prices;
- To the extent feasible, establish benchmarks using data that pre-date the adoption of AB 32; and
- Eliminate the cap adjustment factor for those industries deemed to be highly exposed to leakage. (CSCME2)

Response: As noted in the Staff Report, we are committing to monitoring how covered sectors, especially those who receive free allocation, address carbon costs once the program is in place. Should ARB find that leakage is occurring despite the safeguards in the regulation, ARB will examine all feasible mechanisms to address leakage, including border adjustments or changes to the allowance distribution methods in future amendments to the regulation. In the first set of 15-day regulation modifications, we determined a benchmark based on the "best in class" for the cement sector. This approach means that we expect at least one facility's emissions intensity to be at or below the benchmark at the outset of the program. In establishing these benchmarks, we used data available to us under our mandatory reporting requirements to the extent feasible and supplemented these data with industry-provided data if reported data were insufficient or unrepresentative. We believe that all industries should be treated equitably in the cap-and-trade program, and therefore the cap adjustment factor is necessary for all industries. However, we have kept the less-aggressive cap adjustment factor in the regulation for those sectors, including cement, which have more than 50 percent process emissions in their total production intensity.

C-110. Comment: The concept of a cap adjustment factor is fundamentally incompatible with CARB's mandate to minimize leakage to the extent feasible. By reducing the per-unit allowance allocation rate for all industries, regardless of their assessed leakage risk, the cap adjustment factor unnecessarily and arbitrarily exposes industrial sources to net compliance costs that will not be faced by unregulated competitors. In the event that CARB does not eliminate the cap adjustment factor, a differentiated cap adjustment factor for the cement industry is justified. CARB has appropriately and justifiably modified the cap adjustment factor for the cement industry to reflect the fact that process emissions limit the scope of its technologically-feasible and cost-effective abatement opportunities. However, rather than simply reducing the decline by half, CARB should calculate the cap adjustment factor as a weighted average between process emissions and combustion emissions, with the former receiving a factor of 1.0 and the latter receiving a factor equal to the general cap adjustment for that year. With this small revision, the cement industry's cap adjustment factor values would more precisely conform to the underlying policy rationale. (CSCME2)

> **Response:** We believe our proposed approach (reduce the declining factor for cement sector by 50 percent) is appropriate to take into consideration the high process emission ratio in the cement sector and to administer the program efficiently. As we have noted, a cap adjustment factor for all industries ensures equitable incentives to all producers, to minimize leakage as a result of the cap-and-trade program.

C-111. Comment: If exposed to significant competition from unregulated jurisdictions, domestic facilities must choose between passing realized costs through to consumers and suffer a loss of market share, absorb them and experience a loss of earnings and eventual disinvestment, or a combination of both. In any scenario, a transfer of output, jobs, investment, and other economic activity from inside the regulated jurisdiction to outside the regulated jurisdiction will result. The risk of emissions leakage is greatest within emissions-intensive, trade-exposed industries with relatively few cost-effective abatement opportunities and high differentials between the GHG intensities of domestic and imported products. The California cement industry exhibits precisely such characteristics. (CSCME2)

> **Response:** We recognize that the risk of emissions leakage is greatest within emissions-intensive, trade-exposed industries with relatively few cost-effective abatement opportunities and high differentials between the GHG intensities of domestic and imported products. We believe our approach to allocate free allowances for transition assistance and trade exposure protection will minimize leakage risks. In addition, ARB will monitor the implementation of the cap-and-trade regulation and will develop appropriate responses to rectify any identified issues.

C-112. Comment: The proposed cap and trade program does not minimize leakage. It exposes facilities within vulnerable sectors in general and the cement industry in particular to costs that are not imposed on out-of-state competitors. CARB has not revealed any analysis or substantiated its assertion that the proposed regulation minimizes leakage to the extent feasible. CARB's proposed approach to allowance allocation fails to minimize leakage in the industrial sector in general and the cement industry in particular. CARB has proposed to base the cement metric on the level of clinker production at a particular facility and adjusting it based on the average level of gypsum and limestone used in the cement shipped from that facility in the same year. CSCME supports this approach as a sound and practical method for implementing a cement benchmark in a manner that avoids artificial variations in measured output and eliminates perverse incentives. Furthermore, we recommend that the following formula be used to implement CARB's proposed approach: O=P(1+G/C+L/C) Where, O = cement output in a given compliance year, P = clinker production in a given compliance yea, G = gypsum consumption (i.e., ground) in a given compliance year, L = limestone consumption (i.e., ground) in a given compliance year, C = clinker consumption (i.e., ground) in a given compliance year. (CSCME2)

> **Response:** We believe the design of our system for free allowance allocation will minimize leakage. But until the program is in place, we do not have the data to substantiate the program's effectiveness. Our analysis for leakage is presented in Appendix K of the Staff Report. We considered various output metrics for calculating allowances before selecting the benchmarking metric of allowances per short ton of adjusted clinker and mineral additives produced. We agree that the strongest incentive to continue California production is to have allocation tied to the emissions obligation for a given year, as this comment suggests. We modified our allocation approach to address this concern in the first set of 15-day regulation modifications.

C-113. Comment: CSCME strongly supports the concept of differentiated assistance that is based on an objective assessment of each industry's leakage risk. CSCME also agrees with CARB's assessment that the cement industry is at a high risk of leakage and that an assistance factor of 1.0 throughout the 2012-2020 timeframe is appropriate and necessary. Nevertheless, CARB's leakage analysis can be improved in several respects to yield a more accurate and robust assessment of each industry's leakage risk. We believe that such refinements will bring the cement industry's extreme leakage exposure into better focus and highlight the need to consider this in all aspects of the allowance allocation formula. (CSCME2)

> **Response:** We agree. Per Resolution 10-42, we will continue to review information concerning the emissions intensity and trade exposure of different industries in California. We will recommend to the Board changes to the leakage risk determinations, if needed. In addition, we will monitor the implementation of the cap-and-trade regulation and will develop appropriate responses to rectify any identified issues.

C-114. (multiple comments)
Comment: CARB proposes to address leakage solely through allowance allocation. They have dismissed more effective approaches without sufficient cause or justification. Please consider the use of border adjustments to address leakage in the industrial sector, and provide a detailed proposal to combine allowance allocations and a border adjustment to provide maximum leakage protection. (CSCME2)

Comment: For a capital intensive industry like cement, any delay in adjusting the program to address leakage will cause irreversible damage that cannot be remedied with a border adjustment or other measure imposed "after-the-fact" when market share has been seriously eroded and recovery is no longer feasible. (CSCME2)

> **Response:** We believe, at this point, there are insufficient resources to implement border adjustment. Per Resolution 10-42, we will continue to review the technical and legal issues related to implementation of a border adjustment to impose obligations on importers of cement that are equivalent to those faced by California cement manufacturers under the cap-and-trade regulation, and to implement such a provision, if it is feasible and necessary, to avoid leakage in the cement sector. We will continue working, with input from stakeholders, on the possibility of implementing border adjustment for maximizing leakage protection.

C-115. Comment: CARB substantially underestimates the trade intensity of the California cement industry, and, misclassifies it as "moderately" trade exposed. In assessing the risk of leakage, CARB analyzes GHG intensity, and the extent to which industrial sectors could pass through compliance costs based on the level of trade exposure or intensity for each industry. According to CARB's analysis, the trade intensity of the national cement industry, as measured by the volume of trade as a share of domestic consumption, is 16 percent. This places it within CARB's "medium" trade intensity category. This national trade intensity, however, severely underestimates the degree of import competition in California. The California cement industry's trade intensity during 2003-2008 is estimated to be approximately 41 percent. This is more than twice as high as CARB's assessment of its trade intensity (16 percent) and well beyond CARB's "high" threshold (19 percent). Although the uniqueness of the data may preclude CARB from performing a similar analysis on all other industries, CARB cannot ignore this clear and convincing evidence when assessing the cement industry's trade exposure, especially given the acknowledged limitations of its current approach. (CSCME2)

> **Response:** We observed that the level of cement import varies significantly depending on the robustness of domestic market. When the demand is high, more cement is imported to meet the demand. As part of continued analysis, we will consider other factors suggested in addition to trade data.

Food Manufacturing

C-116. Comment: The formula for trade exposure and emissions leakage should be reevaluated to recognize the complexity and impact of agricultural import and export markets. Food processing should be moved to the "high" leakage risk category, due to increasing international and domestic markets. For example, peach imports from China increased 30 percent increase in 2010 compared to last year's volume. (ACC1, ACC3)

> **Response:** Our analysis of data supports classifying food processing as low in emissions intensity and medium in trade exposure, and a medium risk for

leakage. Staff is aware that there are different trade exposures among different subsectors (e.g., vegetable or fruits processing versus dairy) and some subsectors' trade exposure is high. However, using the current evaluation framework, no sector will be classified high in leakage risk if emission intensity is low, which is the case for all covered food facilities. Per Resolution 10-42, we will continue to review information concerning the emissions intensity and trade exposure of different industries in California. We will recommend to the Board changes to the leakage risk determinations, if needed. In addition, we will monitor the implementation of the cap-and-trade regulation and will develop appropriate responses to rectify any identified issues.

C-117. (multiple comments)

Comment: The staff report states that domestic competition will be problematic as it relates to the food and agricultural industry. A different approach should be taken for food processing in determining compliance costs and/or emissions intensity. The emissions intensity variable in the product-based allocation calculation should be replaced with another variable that truly represents the cost of compliance for the food industry. Staff should take more time to work with the food processing industry to determine an appropriate factor for this variable. (ACC1, ACC3)

Comment: Within the regulation, staff realizes the importance of domestic competition and the ability of emissions leakage to other states, granting easier access to California markets. Staff also observed that emissions intensity may not play a direct role in emissions leakage.

However, the report also states that emissions intensity is to serve as a "proxy" for compliance costs. This assessment is not accurate for the food industry. The California Air Resources Board (CARB) staff assumes a "low" emissions intensity for the food industry, while compliance costs are quite higher for food processing when domestic and international markets are lost to lower-priced competition and food processors are left competing with companies in an auction market that has no price caps for allowances. This is coupled with the fact that the vast majority of food processing is a seasonal industry in which emissions are generated. (ACC3)

Response: The commenters suggest that the emissions intensity variable in the product-based allocation calculation should be replaced with another variable that truly represents the cost of compliance for the food industry. We believe that that approach taken in the leakage analysis is appropriate to use for all sectors. The analysis is broken down into two measures of leakage: emissions intensity and trade exposure. Emissions intensity is strictly a measure of emission per value added and does not take into account other facilities in other regions. Instead, the trade exposure takes into account the risk associated with outside competition. In the leakage analysis, we compared this approach to the European Union Emissions Trading System (EU ETS) approach, but needed to include domestic competition. In our analysis, we found the food industry had a low emissions intensity relative to the rest of California industries and a medium trade exposure risk. This led us to place the food industry in the medium leakage risk category. We understand the concerns with the analysis, especially the access to data. Thus, we will continue to evaluate the risk of emissions leakage in accordance with Resolution 10-42 and make recommendations to the Board for any changes necessary to minimize this risk.

C-118. Comment: In Appendix L, the EAAC assumes companies will fluctuate to variable power sources, depending on the price available for those sources. The opportunity for fuel substitution is minimal in the short and long term because many of our food processors are already utilizing the cleanest forms of fuel and technology. Absent this transition, the analysis goes on to state that reducing output due to price increases is the second option to reduce greenhouse gas emissions. On page L-27, the report states “higher prices will elicit a reduction in the quantity demanded for these products, leading to a reduction in greenhouse gas emissions.” When applying this theory to the food industry, it underscores our concerns about emissions leakage and the need to protect our local food industry. (ACC3)

Response: In developing our approach, we considered the information in the Economic and Allocation Advisory Committee (EAAC) report as one piece of information. Our analysis includes other sources of data detailed in Appendix K of the Staff Report. We determine leakage risk using emissions intensity and trade exposure as two central measures. We analyzed emissions intensity data for all industrial sectors. We then selected natural break points in the emissions intensity spectrum. Industrial sectors are placed into the high, medium, low, and very low categories of emissions intensities based on these break points. For assessing trade exposure we considered various approaches before choosing trade share as the metric to classify industrial sectors for trade exposures. We believe that our leakage risk determinations are supported by available data and are expected to be protective of leakage risks.

C-119. Comment: It should be noted that facilities used to produce food are dedicated to the specific commodity. Movement from food production to another type of market, or even another type of commodity is highly unlikely due to the dedicated nature of the facilities. Equipment, facilities lay-out and labor are highly-specialized and cannot easily be transformed to other types of production. Should the cost of producing food become too high, a processor cannot enter another type of manufacturing without millions in costs to overhaul the entire plant. Additionally, a food processor cannot interchange between types of food produced because the equipment is so specialized. For example, a tomato processor cannot go into almond processing in the near future, without major investments. (ACC3)

Response: We recognize that industrial facilities are highly specialized and their processes are not easily interchangeable. We developed an allowance allocation system to provide industrial sectors with transition assistance that would incentivize them to innovate and protect them from leakage risk.

C-120. Comment: As experienced in many sectors of the food and agriculture industry, certain market segments could be flooded with imports in a matter of months such as the previously-stated case in the processed peach industry. CARB staff should be required to report to the Board on the findings of impacts on food processing as the regulation is underway so as to avoid these types of situations. (ACC3)

> **Response:** As noted in Resolution 10-42, we will report to the Board annually on all shifts in business activity that may result in emissions leakage and changes in market share for covered entities and sectors.

C-121. Comment: Emissions leakage for the food processing industry is our central concern in this regulation. Agricultural products are very sensitive to low-cost competitors in domestic and international markets. Many of these markets can flood segments of our industry in a matter of months, such as the current situation in the canned peach industry. (ACC2, ACC3)

> **Response:** We are committed to protecting against emissions leakage, which will in turn protect against economic leakage. As noted in the Staff Report, we are committing to monitoring how covered sectors, especially those who receive free allocation, address carbon costs once the program is in place. Should ARB find that leakage is occurring despite the safeguards in the regulation, ARB will examine mechanisms to address leakage.

C-122. Comment: Food manufacturing is located in the second Industry Assistance Factor tier (Industry Assistance Factor of 100 percent; 75 percent; 50 percent), and should be moved to the top industry assistance factor tier due to price pressures from international markets. Even a minimal increase in costs could displace U.S. markets, giving more ground to domestic and international competitors. (ACC1, ACC3)

> **Response:** The assistance factor is based on leakage risk classification. Our analysis of data supports classifying food processing as medium risk for leakage. As noted in Resolution 10-42, we will report to the Board annually on all shifts in business activity that may result in emissions leakage and changes in market share for covered entities and sectors.

C-123. Comment: Most California industrial sectors are global players. This is particularly true of the California food processing industry. Food processing is a highly competitive business that tends to be characterized by small financial margins, making our products sensitive to low-cost competitors in domestic and international markets. CLFP believes that if the compliance costs become too high, then a number of food processors will become uncompetitive, losing customers and business to competitors not burdened with added compliance costs. (CALFP1)

> **Response:** Our program is designed to provide industrial sectors with transition assistance and leakage risk protection. The food processing sector will be

allocated with appropriate levels of free allowances during all compliance periods if the risk remains.

C-124. (multiple comments)
Comment: In Appendix J, the regulation states that the industry assistance factor is the ability an industry has to pass-on carbon costs. Staff utilizes the NAICS classification standards to determine the leakage risk that will be assigned to each industry. In utilizing only a three-figure NAICS designation, the leakage risk for fruit and vegetable food processors is seriously diluted. As such, food processors will face serious difficulties in adapting to the low-carbon business landscape envisioned in the proposed regulation given the current economic downturn, the unique nature of the food processing industry in California, and the intense competition for national and international market share. (CALFP1)

Comment: CLFP recommends delineating the NAICS classification to a finer detail (four or six digits) for fruit and vegetable food processors. (CALFP1)

Response: We recognized the limitations of utilizing a three-digit NAICS classification for evaluating the food processing sector's leakage risks. Currently, data for higher-digit NAICS state-specific classifications are not available. We supplemented our analysis with data from other sources before finalizing our classification.

Leakage risk is mainly used for assigning assistance factors. The assistance factor used for the first compliance period is identical for all leakage risk levels. The allocation to industrial sectors for the initial period is not affected by potential misclassification of leakage risks. Per Resolution 10-42, we will, during implementation, continue to review information concerning the emissions intensity and trade exposure of different industries in California, and to recommend to the Board changes to the leakage risk determinations, if needed. We believe our system of allowance allocation to be equitable to all facilities within and across industrial sectors.

C-125. (multiple comments)
Comment: CLFP recommends developing a new matrix for determination of leakage risk for fruit and vegetable food processors. (CALFP1)

Comment: CLFP recommends staff to develop techniques to evaluate the trade exposures of the fruit and vegetable food processing industry and that staff include affected industry stakeholders in developing these alternative techniques. (CALFP1)

Response: Per Resolution 10-42, we will, during implementation, continue to review information concerning the emissions intensity and trade exposure of different industries in California, and to recommend to the Board changes to the leakage risk determinations, if needed. We will include stakeholders in our deliberations.

C-126. Comment: CLFP recommends staff to compile an industry study in concert with the CLFP and report to the Board on progress. (CALFP1)

> **Response:** This is an issue to be addressed during implementation of the regulation.

C-127. Comment: Ag and food processing are linked. You cannot separate us because the production would fall mightily. And anything that happens to us will also affect them. (CALFP2)

> **Response:** We recognize that agriculture and food processing are linked. We are not suggesting a separation of the linkage between agriculture and food processing. Free allocation is provided to industries based on their emissions intensity and trade exposure, and is not based on linkage to raw materials or their suppliers. Transition assistance is not necessary for industrial facilities emitting less than 25,000 CO_2e metric tons per year because they are not subject to a compliance obligation under the California Cap-and-Trade Program. The food processing facilities included are those that met the emissions threshold for receiving free allowances.

C-128. Comment: We request ARB staff to work with us to address leakage risk as specified in the California League of Food Processors written comments. In the development of the emission intensity matrix, staff has used a high level of segregation, thus combining unlike industries into one category. We request staff to increase the differentiation among our industry which will result in clearly showing a high leakage rate. Specifically, the United Nation's Commodity Trades Statistics Database uses a five digit differentiation as opposed to ARB's three. The statistics read that the U.S. imports 50 percent more dehydrated onion since 2007. China's garlic imports alone have risen from 50 million tons to 130 million. The international imports together account for 68 percent of the market share. The U.S. and California market shares have eroded due to international cost advantage. California, specifically the onion and garlic dehydration industry, has closed almost 40 percent of its capacity, eliminating 900 jobs over the past five years in the area, especially in the San Joaquin Valley. Continued erosion of our competitive position is a major factor when we consider operating and moving out of state and to foreign source productions. (OLAMWC)

> **Response:** Because of the lack of available data, aggregating the food processing industry was necessary in our analysis. Per Resolution10-42, we will, during implementation, continue to review information concerning the emissions intensity and trade exposure of different industries in California, and to recommend to the Board changes to the leakage risk determinations, if needed. The assistance factor used for the first compliance period is identical for all leakage risk levels, and allocations for the initial period will not be affected by potential misclassification. We will address this issue in deliberations during implementation.

C-129. (multiple comments)
Comment: The comments in this letter are focused on the GHG emission leakage analysis specific to biogum production at CP Kelco San Diego. CP Kelco is the only covered entity in the cap and trade program classified with NAICS code 311999 - All Other Miscellaneous Food Manufacturing. All facilities under the Food Manufacturing three digit code of 311 are classified by the Air Resources Board (ARB) as a "Medium" Leakage Risk facility. Based on data specific to CP Kelco San Diego, this facility is requesting to be re-classified by the Air Resources Board (ARB) as a "High" Leakage Risk facility. Failure to do so could lead to a net increase in GHG emissions from overseas competitors in China, contrary to the stated goal of AB 32. The other facilities with NAICS code 311 manufacture final food products or primary food ingredients. CP Kelco is unique in that this facility manufactures a product that is a property enhancer or trace ingredient in other food products. In contrast to most other food manufacturers, CP Kelco has a significant international market, particularly in Asia and Japan. Also in contrast to other food manufacturers, CP Kelco's products require a very complicated and energy intensive manufacturing process. (CPKELCO)

Comment: The three digit NAICS code 311 - Food Manufacturing covers an extremely wide range of manufacturing facilities. There are nearly 700 subsectors beneath the 311 three digit classification. For most other sectors, ARB has created classifications based on NAICS six digit codes, which results in a much smaller number of subsectors in the classification and much greater similarity for facilities within the classification. In a classification as broad as food manufacturing, it is difficult to state with any level of certainty that all manufacturing processes should have similar emissions intensity. In fact, it is very likely that some sub-sectors are as different in emissions intensity as facilities in distinct three-digit sectors. That is to say, that CP Kelco's emission intensity is just as likely to be similar to a facility in the glass manufacturing or paper manufacturing industry as it is to be similar to a facility in the breakfast cereal manufacturing fruit and vegetable canning industry. This is in fact the case, and more details are provided in the following section. Based on CP Kelco San Diego's unique attributes and the fact that this facility is the only covered entity with NAICS code 311999, it may be appropriate for ARB to separate this code from the remainder of the Food Manufacturing Sector for the purpose of GHG emission leakage analysis. (CPKELCO)

Comment: CP Kelco analyzed trade-sensitive data specific to the San Diego facility for comparison to the ARB Emissions Intensity metric. The result is an Emissions Intensity value (CO_2e/$M Value Added) that is several times higher than the Emissions Intensity value calculated for the Food Manufacturing classification in general. The value is high enough to place CP Kelco in the "Medium" Emission Intensity Classification and is high enough to qualify as one of the ten highest sectors for emissions intensity. CP Kelco may be able to share the data used in the calculation directly with ARB staff if an agreement can be reached to ensure that all trade-sensitive data will be kept confidential. Based on the site-specific data, it is clear that CP Kelco San Diego's Emission Intensity is higher than other facilities in the Food Manufacturing sector and that there is a greater risk for emissions leakage if the situation is not addressed. (CPKELCO)

Comment: CP Kelco's market is different from other businesses in the Food Manufacturing sector, since a higher percentage of the sales occur outside of California. Additionally, demand for the products produced by CP Kelco San Diego has increased more in foreign markets, notably in Asia and Japan, than in domestic markets, increasing the potential for manufacturing to also shift to those geographic areas. This will become more likely if the plant's costs increase as they would under the proposed Cap and Trade program, particularly if CP Kelco San Diego remains in the "Medium" Leakage Risk category. (CPKELCO)

Comment: The CP Kelco San Diego Emissions Intensity data demonstrates that the facility should be classified as at least "Medium" Emissions Intensity as opposed to the "Low" Emissions Intensity that applies to the remainder of the Food Manufacturing sector. The market share data for biogum production shows that CP Kelco San Diego has significant trade exposure. "Medium" Emissions Intensity and high trade exposure should classify CP Kelco San Diego as "High" Leakage Risk.

Based on recent experience, it is fairly clear that an increase in production costs will result in reduced market share for CP Kelco San Diego. It is expected that this market share would be absorbed by competitors in China that consume electricity and/or steam from coal-fired facilities. The transfer of biogum production from San Diego to another facility will result in not just a transfer of GHG emissions from San Diego to another state or country, but will result in a net INCREASE in GHG emissions and a loss of California-based jobs. As discussed above, the San Diego plant operates a very efficient, natural gas-fired cogeneration facility. Chinese biogum plants typically consume energy from coal-fired utilities. The electricity and steam supplied to the CP Kelco plant in Shandong, China is provided by a coal-fired plant that is located next door. These competitors utilize both less efficient technology and fuels that have higher GHG intensity. Based on these two factors, it is conceivable that production "leakage" from CP Kelco San Diego could result in the doubling of the GHG emissions associated with the transfer of biogum production from San Diego to other facilities outside the state. Re-classification of the CP Kelco San Diego plant from "Medium" Leakage Risk to "High" Leakage Risk would reduce the probability of this occurring. Since CP Kelco is the only covered entity in NAICS code 311999, it would be possible for ARB to simply add this code to the group of sectors in the "High" Leakage Risk classification. (CPKELCO)

Comment: The GHG leakage analysis presented for CP Kelco San Diego demonstrates that the facility should be classified as a "High" Leakage Risk and should be afforded the same protections provided to other facilities in this classification. Failure to do so would result in GHG emissions leakage and likely a significant net increase in global GHG emissions. The calculation of the Emissions Intensity metric requires the use of trade-sensitive data that CP Kelco is not able to disclose in this public document. CP Kelco is requesting to meet with ARB staff in person to discuss the analysis in more detail and potentially share the specific data used in the calculations if an agreement can be reached in order to ensure that the trade-sensitive data will be kept confidential. We look forward to hearing from you at your earliest convenience. (CPKELCO)

> **Response:** We recognize the limitations of utilizing the three-digit NAICS code 311 which covers a wide range of food manufacturing facilities for evaluating the food processing sector's leakage risks. Leakage risk is mainly used for assigning assistance factors. The assistance factor used for the first compliance period is identical for all leakage risk levels. Allocation for the initial period is not affected by any potential misclassification of leakage risks. Staff will work to evaluate leakage risk at a more disaggregated level to address CP Kelco's concerns prior to the start of the second compliance period.
>
> Currently food processing facilities are to be allocated using the energy-based allocation calculation methodology. As noted in Appendix J of the Staff Report, the option exists for product-based benchmarks to be developed in subsequent compliance periods for industries being allocated under the energy-based methodology during the first compliance period.
>
> We designed the regulation to minimize leakage by placing covered entities on an equal footing with their non-covered competitors. We are committed to monitor how covered sectors address carbon costs once the program is in place. We will work with affected and interested parties to identify additional sources of information at the state level that could improve our ability to monitor leakage. Should we find that leakage is occurring despite the safeguards in the regulation, we will examine mechanisms to address leakage, including border adjustments or changes to the allowance distribution methods.

Glass

<u>Flat Glass</u>

C-130. Comment: GANA supports recognition of the glass industry as a high leakage risk and a recipient of free allowances to help reduce the possibility of leakage from the glass industry. GANA supports this approach for the flat glass industry due to its energy intensity, its general inability to pass costs along to consumers, and its inability to respond quickly to any significant step change requirements to lower CO_2 emissions. GANA notes that some flat glass products are integral to the successful adaptation of "green" technologies like solar energy that form an integral part of the overall GHG reduction goals of AB 32. (GANA)

> **Response:** No response necessary.

C-131. Comment: GANA supports retention of the assistance factor at 100 percent for the flat glass industry. (GANA)

Response: No response necessary.

Fiber Glass

C-132. Comment: The challenge is to assist the California fiber glass insulation industry and to deal with threats in a way that is fair, reasonable, and predictable. For example, the State's fiber glass plants are readily subject to leakage that should entail free allowances for all three compliance periods. (NAIMA)

Response: Based on our analysis, we have categorized the fiber glass sector as medium leakage risk which provides for some free allocation for all three compliance periods.

C-133. Comment: Fiber glass insulation (mineral wool) has been given a medium level of allowances, which equates to 100 percent in 2012–2014; 75 percent in 2015–2017; and 50 percent in 2018–2020. The other two glass sectors (flat glass and glass packaging) received 100 percent allowances for all three compliance periods. CARB has justified that distinction based on its perception of the effect of foreign competition on each segment of the glass industry. CARB's effort to stop leakage is really an effort to reduce the effect on industry and employees from the implementation of the cap and trade program. Given that simple premise, the facts fully support 100 percent allowances for fiber glass insulation for each of the three-year compliance periods designated in the legislation. CARB should recognize that if the California fiber glass operations are not economically viable as a result of AB 32, some of NAIMA's members might close their plants or significantly reduce capacity. (NAIMA)

Response: Our analysis of emissions intensity and trade exposure, presented in Appendix K of the Staff Report, supports classifying fiberglass, flat glass, and container glass differently for leakage risks. Our goal is to prevent emissions leakage with the appropriate level of free allowances. We are using an approach for allocating free allowances that is equitable to all sectors. While emissions leakage and economic leakage are linked, a system for preventing emissions leakage requires different means and design than a system for preventing economic leakage; however, limiting emissions leakage will also limit economic leakage. We note that reducing production will also reduce the amount of allocation to industrial producers. This provides an incentive to continue production in California while also incentivizing reducing the emissions intensity of that production.

C-134. Comment: CARB's proposed Cap-and-Trade program, as currently written, could ultimately result in closing fiberglass plants or curtailing their operations within the State. That outcome would result in more of the California market being supplied by manufacturing facilities in other states, Canada, and Mexico. Fiber glass insulation is an important contributor to the California economy, through direct manufacturing, shipment of finished product to markets within California and other western states, and export of product to foreign markets. Fiber glass insulation promotes energy efficiency, environmental preservation, and reduces pollutants, including greenhouse gases. If fiber glass insulation would not be available, the supplies of alternative insulating materials would not be sufficient to supply the demands of the market. Raising the cost of insulation products by raising the costs of doing business for fiber glass insulation manufacturers or by artificially reducing the supply of available insulating materials will reduce the ability of the State to meet its greenhouse gas emission reduction goals. (NAIMA)

> **Response:** We disagree. We have developed a system for free allowance allocation to provide transition assistance for industry to innovate toward a low-carbon economy and prevent trade risks. As noted in Resolution 10-42, we will report to the Board annually on all shifts in business activity that may result in emissions leakage and changes in market share for covered entities and sectors. If there is a need for adjustment, we will update the allowance allocations methodology to correct unintended consequences.

Container Glass

C-135. (multiple comments)
Comment: The container glass sector as a whole has a "high risk" of leakage due to its high energy intensity and trade exposure. Add in the cost-sensitivity of the business and the already high cost of manufacturing in California, and it becomes clear that the "protections" in the proposed Cap and Trade Program intended to mitigate this "high risk" for container glass manufacturing currently fall well short of providing the necessary relief. (SMITHS)

Comment: The container glass sector's "high risk" vulnerability to leakage requires additional protections in the proposed Cap and Trade Program to avoid making California facilities uncompetitive. California's container glass sector is already more efficient in terms of limiting and controlling GHG emissions compared to facilities in other jurisdictions. (SMITHS)

Comment: California's container glass facilities are generally more expensive to operate and therefore among the most susceptible to "leakage." (SMITHS)

> **Response:** We believe our program will provide adequate protection for leakage risk and transition assistance for the container glass sector. We determine leakage risk using emissions intensity and trade exposure as two central measures. We have classified the leakage risk for the container glass sector as high for allocating free allowances. The container glass sector will be allocated allowances using an assistance factor of 100 percent for all three compliance periods. The design of our cap-and-trade program rewards early action in controlling GHGs.

C-136. Comment: Under the proposed regulation, the targeted level of stringency would be created by evaluating each industrial sector’s emissions intensity during a historical base period and targeting the benchmark to allocate 90 percent of its level per unit product. This reasoning appears to make no distinction between sectors with low and high risks of leakage and thus could create an additional 10 percent shortfall in allowances for the "high risk" glass container sector, which is already highly efficient. (SMITHS)

> **Response:** In the first year of the program the most efficient facilities in each sector—those with efficiencies at or better than the benchmark—will be receiving allowances equal to or greater than they will need for compliance. Less-efficient facilities will need to purchase additional allowances or offsets to fulfill their compliance obligations. This approach recognizes early action; minimize the potential for windfalls that could result due to excessive free allocation; and gives all industrial facilities the correct incentive to reduce GHGs. Although the benchmark stringency is not a function of leakage risk, the other components of allowance allocation, most notably the assistance factor are a function of leakage risk.

C-137. Comment: The container glass sector's cap adjustment factor should remain constant at 1.0 until at least 2020. The current cap erosion would require a 15 percent reduction in allowances for the glass container sector by 2020, despite the fact that there is no means of achieving such reduction. Even reducing glass production, the surest way to reduce net GHG emissions, will fall short of providing a sustainable reduction given the output-based allocation formula in the proposed rule that would merely result in fewer allowances going forward. At a minimum, the cap adjustment factor for container glass should not be any lower than that proposed for the cement manufacturing industry in section 95891. The container glass sector, like cement manufacturing, is a high risk sector for leakage and has the same types of GHG emissions as the cement industry. (SMITHS)

> **Response:** The cap adjustment factors for all industrial sectors other than those whose process emissions are greater than 50 percent of their GHG emissions are the same. While both container glass and cement manufacturing are both classified as high risk for emissions leakage, the cement sector's emission intensity is about eight times that of container glass manufacturing. Also, the amount of process emissions relative to the total emissions is about 60 percent in the cement sector. The glass sector's process emissions relative to total emissions are less than half of those of cement. Therefore, it is not justifiable to use the same cap adjustment factor for container glass and cement manufacturing.

C-138. Comment: Establish actual annual production in the compliance year as the basis for allowance allocation, rather than looking back three years. The three-year look-back has the effect of restricting increased output to meet market demand from wineries for bottles at a time when recovery from current national economic crisis is still on the horizon. Without a forward-looking methodology for allocating allowances to the glass container sector, the effect will be higher costs on the wine industry and other food and beverage industries which rely on California-produced glass containers and relocation of jobs to out-of-state glass producers. (SMITHS)

> **Response:** We modified the equation for calculating product-based allowance allocations. The addition of the "true-up" term ($O_{a,trueup}$), for adjusting outputs not properly accounted for in prior years' allocations, in the equation for calculating allocations under section 95891, have adequately addressed the concerns.

Natural Gas

C-139. Comment: The allowances allocated for the purposes of industry assistance in section 95870(d) should also include facilities providing the Pipeline Transportation of Natural Gas. Establishments primarily engaged in the pipeline transportation of natural gas from processing plants to local distribution systems, NAICS code 486210, should be added to Table 8-1 as these entities have some leakage potential since interstate pipelines operating compressors outside of California have some substitution capabilities for facilities inside California. This industrial sector includes both compressor stations required for pipeline transportation of natural gas and the injection and withdrawal of natural gas from storage fields.

The allowances allocated for the purposes of industry assistance in section 95870(d) only include the industrial sectors in Table 8-1. Omitted from that list are facilities providing the Pipeline Transportation of Natural Gas. Establishments primarily engaged in the pipeline transportation of natural gas from processing plants to local distribution systems, NAICS code 486210, should be added to Table 8-1. This industrial sector includes both compressor stations required for pipeline transportation of natural gas and the injection and withdrawal of natural gas from storage fields. They are covered entities under section 95811(a)(8) or (12). Companies in this sector include more than natural gas utilities (e.g., interstate pipelines, and independent storage operators), and so should be included here rather than in section 95870(c)(2). These entities do have some leakage potential since interstate pipelines operating compressors outside of California have some substitution capabilities for facilities inside California. For example, El Paso Natural Gas has compressor stations in Arizona, across the California border from stations operated by Southern California Gas Company. A recent California Energy Commission Report indicated that there is 90 BCF of storage capacity connected to California, but outside California, in competition with 219 BCF of utility-owned and independent storage in California. This sector should be added to Table 8-1 and should be evaluated by the same criteria as the industries already included in Table 8-1. (SEMPRA1)

> **Response:** In establishing the framework for leakage risk assessment, we focused on the sectors that have tradable outputs since competition occurs when multiple suppliers can supply the same (substitutable) goods or services.
> We did not include pipeline transportation of natural gas because we believe that the pipeline services have to be located between gas wells and end users; they cannot be moved to other places just to seek lower costs. We understand that

the possibility of compressing station shuffling would occur only along the border; however, the majority of compressing stations have to stay in California to serve California-based customers.

However, per Board Resolution 10-42, staff will continue evaluating the methodology for leakage risk assessment. If stakeholders provide us with additional information, staff will review them. Additional information could include excess capacity of compressing stations in neighboring states close to California border, or methodology to assess trade exposure for pipelines.

Resolution 10-42 indicates that this evaluation of leakage risk assessment will occur when we initiate a public process for determining whether allowances should be allocated directly to natural gas utilities on behalf of their customers, and we will recommend to the Board what method should be used for that allocation. This would be implemented prior to the initial allocation of allowances for the second compliance period.

Refineries / Oil & Gas

C-140. (multiple comments)
Comment: The petroleum refining and extraction sectors are categorized inappropriately as high risk. In fact, these industries face very low leakage risk; statewide extraction and refining output does not change measurably with changes in worldwide energy prices. Extraction opportunities are place-based, and refining capacity in place already within the state is not likely to relocate. (EDF1)

Comment: EDF disagrees with the categorization of petroleum extraction and refining as a high leakage risk, so CARB needs to revisit the treatment of both petroleum sectors. (EDF1)

Comment: CARB should maintain oil and gas extraction in the "high" risk category for emission leakage. (CONOCO)

Response: Petroleum extraction is classified as high leakage risk and petroleum refining is classified as medium leakage risk. These classifications are supported by available data. We determined leakage risk using emissions intensity and trade exposure as two central measures. Our analysis is detailed in Appendix K of the Staff Report. We analyzed emissions intensity data for all industrial sectors, selected natural break points in the emissions intensity spectrum, and placed industrial sectors into the high, medium, low, and very low categories of emissions intensities based on these break points. For assessing trade exposure, we considered various approaches before choosing trade share as the metric to classify industrial sectors for trade exposures.

C-141. Comment: Examination of published California Department of Oil, Gas, and Geothermal Resources data show that California domestic captive oil production is not sensitive to leakage at the carbon prices expected under the California cap & trade program ($15-$30 projected in 2020, according to CARB's staff report). As demonstrated in Figure 1, oil production has been on a steady decline over the past decade, and fuel price has had no perceptible impact on production, even with a five-fold crude oil price increase. Adding a carbon price, for example $20/ton, is likely to change the net price received for crude oil production by about one percent at recent oil prices, even if producers pay for 100 percent of their GHG allowances. (ICCT1)

> **Response:** Thank you for the comment. We believe that in the future it may be appropriate to use fuel price as a metric for leakage risk analysis. In the absence of GHG reduction regulations, variation in the price of fuel inputs may shed light on the effect that a price of carbon is likely to have on the cost of production and retail price of products. In the current categorization, we determined leakage risk using emissions intensity and trade exposure as two central measures. At the time of our analysis, this was our preferred approach for projecting potential for leakage. Our methodology is detailed in Appendix K of the Staff Report.
>
> As noted in the Staff Report, we are committing to monitoring how covered sectors, especially those who receive free allocation, address carbon costs once the program is in place. But until the program is in place, we will not have the data to substantiate or negate the concerns raised. Per Resolution 10-42, we will continue to review information concerning the emissions intensity and trade exposure of different industries in California.

C-142. Comment: We support the use of carbon allowances to reduce greenhouse gas emissions. These allowances have the potential of raising billions of dollars to help address the problem. CSS does not agree with the proposed structure to give free allowances to producers until 2015 based on the amount of petroleum they produce. If the goal is to reduce carbon emissions, we need to capture the full cost of the fuels in the price and use the fees imposed to mitigate the environmental damage and health hazards caused from their use. Giving free allowances to refineries is taking a step backwards. It would be a better plan to auction all allowances and use the proceeds to help businesses conserve fuel. The auction of these allowances could provide a source of capital for implementing efficiency measures for our small businesses which, unlike large oil companies, have no ability to set prices for their products and services. (CSS)

> **Response:** We designed a phased approach to the development of an auction system, beginning with a high percentage of free allowances allocated to program participants. We recognize that the long-term success of the program will require significant investment in emissions reductions. However, under current economic conditions, an early emphasis on auction could hamper the ability of California sources to invest in low-carbon technologies. Freely allocating allowances in the early years of the program will help prevent leakage. Allocating the allowances for free using emissions efficiency benchmarks will reward companies that have already made investments in energy efficiency and carbon reductions, and will not penalize those that produce goods in California

using energy-efficient processes. The overall allocation approach includes: creation of an Allowance Price Containment Reserve for cost-containment purposes, free allocation to the industrial sector for transition assistance and leakage prevention, free allocation to electrical distribution utilities on behalf of ratepayers, and auction of the remaining allowances.

C-143. Comment: The refining industry is highly trade exposed and we believe that the treatment of the refining sector as proposed in the draft regulation will result in significant leakage in the second and third compliance periods. This will result in a major negative impact to this value added California industry. We recommend that ARB revise its conclusion that the refining sector is medium trade exposed in the second and third compliance periods, and instead, find that this sector will be highly trade exposed. (TESORO)

Response: As noted in the Staff Report, we are committing to monitoring how covered sectors, especially those who receive free allocation, address carbon costs once the program is in place. But until the program is in place, we will not have the data to substantiate or negate the concerns raised. Per Resolution 10-42, we will continue to review information concerning the emissions intensity and trade exposure of different industries in California. We will recommend changes to the Board on leakage risk determinations, if needed, prior to the initial allocation of allowances for the first compliance period starting in 2013 for industrial sectors not identified in Table 8-1 of the cap-and-trade regulation, and prior to the initial allocation of allowances for the second compliance period starting in 2015 for industries identified in Table 8-1 of the cap-and-trade regulation. We will update the Board annually on the status of the cap-and-trade program, including, to the extent feasible, information on shifts in business activity that may result in emissions leakage and changes in market share for covered entities and sectors.

C-144. Comment: Refiners and other trade-exposed industries that purchase electric power should receive either direct rebates from utilities or allowances to compensate for trade exposure. The proposed regulation does not specifically state how Energy Intensive/Trade Exposed (EITE) entities that import electric power will be compensated for the GHG compliance costs associated with purchased power. Competitiveness of trade-exposed entities can only be maintained if allowance allocation to energy sectors is equitable. Under the proposed regulation, refineries that do not have on-site cogeneration facilities are not at parity with those that do. In the Initial Statement of Reasons, CARB appropriately contemplates direct rebates to residential electricity customers to compensate for the GHG compliance cost. However, in that same document CARB suggests that industrial customers' allowance value might be best provided through energy efficiency benefits, rather than direct cost relief. Codifying such a recommendation would create uncertainty in the extent to which refineries and other EITE entities might be adequately protected. CARB should clarify the regulations regarding importation of power by EITE entities to address the potential impact on competitiveness by adopting one of two approaches. Under the proposed framework, CARB could require the utility to share the benefits of free allowance value with trade-exposed entities through direct rebates. Alternatively, CARB could provide an EITE entity a direct allocation of free allowances for power purchased from a distribution utility. To avoid double counting, CARB should exclude these allowances from the allocation of free allowances to the entity's serving utility. (CONOCO)

> **Response:** An adjustment factor was not made for power purchased in establishing the product-based benchmarks. This is because purchased power may not create an indirect carbon cost in all California utility service territories. It is ARB's goal to see a carbon price properly embedded in all utility rates. If and when this occurs, the compensation for these indirect carbon costs could be incorporated into the product benchmarks (or reductions in these costs created in some other fashion) to help minimize leakage. We will revisit this issue once the California Public Utilities Commission Proceeding addressing utility costs and revenue issues associated with greenhouse gas emissions concludes.

C-145. Comment: Based on CARB's allocation formulas, refiners would receive the majority of industrial sector free allowances. This sector would be the biggest recipient overall behind electric utilities. The value of these allowances at $20 per GHG allowance over the years at 2012 to 2020 is estimated at $4 billion dollars. The leakage risk for refined California surface transportation fuels is low due to unique California fuel requirements and can likely be minimized further without free allocations (through mechanisms such as a border adjustment). (ICCT1)

> **Response:** We evaluated the feasibility of implementing border adjustment before choosing free allowance allocation as a means of emissions leakage prevention. However, at this point we believe that there are many technical and legal limitations, and insufficient resources to implement border adjustments. We will continue to evaluate the feasibility of border adjustments during implementation of the cap-and trade program.

C-146. (multiple comments)
Comment: We agree with CARB staff that additional analysis is warranted (Appendix K-26 and 27) regarding potential leakage risk for domestic captive producers such as oil production facilities. CARB has determined that some allocation decisions (i.e. cogeneration) require further analysis before making any final decisions, and further analysis of domestic captive producers should also precede adoption of any free allocation factors for these sources. (ICCT1)

Comment: Placing large and small refiners within the same category for leakage assistance may not be appropriate. Appendix K-Leakage Analysis specifically notes that the petroleum refining sector was aggregated for leakage analysis. WIRA requests that a separate leakage analysis be done for small refiners as they have unique circumstances. (PMTPETRO1, WIRA1)

Comment: WIRA members do all their business in California and so are more susceptible to leakage. We urge you to ask your staff to allow assessment of leakage, not only among the industries, but among segments of an industry. The presumption of through-put of cost, especially as the transportation fuels, is wrong. If cost could always be passed through, we would never lose money or sell products at a loss. (WIRA2)

Comment: The final regulation should extend full trade exposure protection for refining beyond the first compliance period. We propose that ARB either review the impacts of trade exposure looking at marginal costs and change the status of refining to highly trade exposed; or add a criterion for program monitoring of leakage potential that evaluates the competitive disadvantage of refining due to the lack of linkage or a US national cap & trade program. If neither linkage nor a US cap and trade program is in place by 2014 then ARB should extend full trade exposure protection at 100 percent free allowances for refining. It is important that this evaluation take place as early as possible and well in advance of the second compliance period to avoid the irreversible impacts of investment and jobs transferred to other states. (CHEVRON1)

Comment: The refining industry is clearly under trade pressure from fuel imports. The proposed reduction of the Assistance Factor from 100 percent in the first compliance period to 75 percent and then 50 percent in the subsequent second and third compliance periods, respectively, leaves in-state production capacity vulnerable to increased dependence on imports (and hence supply disruptions). Industry experts anticipate this import pressure to materially increase over the next several years, increasing the industry sectors leakage risk to “High”, where no reduction in the Assistance Factor would be imposed. At a minimum, CARB should re-evaluate the leakage risk preceding each subsequent compliance period and determine of the proposed reduction in the Assistance Factor is warranted. (APC)

Comment: Reassess leakage in the refining sector to consider recent imports of transportation fuels. Consider creating subsectors in the refining group that will properly identify leakage advantages that integrated and larger multi-facility refiners have over smaller, non-integrated refiners. Kern supports using a broad base in determining the sector baseline, since leakage would likely occur to less efficient refiners outside of California. Kern also suggests assigning the refining assistance factor into the high leakage risk category. It may also be necessary to create a subset in the refining sector based on integration and size, in order to prevent large entities from "shuffling carbon efficiencies" among locations to create a carbon advantage within the California Cap and Trade. (KERNOIL1)

> **Response:** We recognize limitations of the data used, but until the program is in place, we will not have the data necessary to substantiate or negate the concerns raised. We will monitor for leakage and adjust free allocation if needed during implementation. Per Board Resolution 10-42, we will continue to review information concerning the emissions intensity and trade exposure of different industries in California. We will recommend changes to the Board on leakage risk determinations, if needed, prior to the initial allocation of allowances for the

first compliance period starting in 2013 for industrial sectors not identified in Table 8-1 of the cap-and-trade regulation, and prior to the initial allocation of allowances for the second compliance period starting in 2015 for industries identified in Table 8-1 of the cap-and-trade regulation. We will update the Board annually on the status of the cap-and-trade program, including, to the extent feasible, information on shifts in business activity that may result in emissions leakage and changes in market share for covered entities and sectors.

C-147. Comment: ARB staff's determination that refining is a medium trade exposed sector is based on the ability to pass through costs and the fact that today's market is balanced with the majority of refined product consumed in California being produced in California. We believe that the analysis is flawed because it does not take into consideration the impacts on the balance of trade once the price of carbon is imposed on the market, nor does it recognize future changes in the market that are currently being signaled today.

- There is no empirical evidence established for the ability of CA refiners to partially or fully pass through carbon costs. Cost pass through will be determined by a variety of market factors as well structural factors associated with the carbon intensity of California refineries and imported products. Since long-term wholesale petroleum prices are driven by the marginal barrel costs of supply, the cost of carbon associated with the last marginal barrel of supply may be zero, if supplied by an imported barrel where no GHG regulations exist. The carbon cost associated with the last marginal barrel of supply from an in-state refiner could be small if the refiner has a low carbon intensity which is associated with simple, non-complex refineries. Therefore the less complex refiners may have more potential to pass through the costs on the marginal barrel.
- Imports and exports are currently balanced indicating a healthy market not a closed one.
- Recent worldwide increases in refining capacity and ARB's own Supplier Diversification initiatives have opened the CARBOB market to refineries worldwide.
- Because gasoline is a mixture of refinery streams, it's relatively easy for any refinery to produce 'some' CARBOB gasoline with minimal additional investment. California refineries have continued to make the more expensive investments necessary to produce a larger proportion of gasoline meeting CARBOB specifications.
- Cost of transportation from states outside California is very small – approximately 5 cents per gallon or less.
- Basing a trade exposure determination on cost pass-through does not recognize the uneven playing field created for competition from outside by the cost of AB 32 compliance imposed on California producers, particularly with rising costs of carbon (expected in 2015 due to lack of linkage). Additional issues are long-term structural disadvantages to the sector from higher costs and the spiral effect that these costs and changes have on long-term investments in the state.

- Even with high trade exposure, California refineries will have to make reductions to meet the declining cap and to pay the added cost of carbon in electricity.
- It is important to recognize that impacts of this decision to add additional burden to the refining sector in the long term is not reversible. If ARB chooses to monitor trade exposure and change the program after seeing leakage, it will be too late. Investment decisions to grow industry out of the state cannot be reversed. ARB should make the trade exposure decision based on whether there are greenhouse gas emissions control programs for refineries throughout the U.S. and whether AB 32 is linked to U.S. and worldwide programs.
- In addition to these detailed comments and recommendations, we have attached comments by the Analysis Group that substantiate that the refining sector should be considered highly trade exposed until there are widespread cap and trade programs that will equalize the costs between states and other jurisdictions. We can arrange a meeting between ARB staff and the consultants to clarify any questions regarding the comments.

We recommend a high trade exposure determination for refining. This meets the objectives of AB 32 better than medium trade exposure because it reduces economic impacts from the program without compromising the required emission reductions to 1990 levels or impacts of the cost of carbon. (CHEVRON1)

> **Response:** We recognize that we need to collect data to analyze impacts on the balance of trade once the price of carbon is imposed on the market, but we believe our analysis of available data supports classifying petroleum refining as medium trade exposure.
>
> Per Resolution 10-42, we will continue to review information concerning the emissions intensity and trade exposure of different industries in California. We will recommend changes to the Board on leakage risk determinations, if needed, prior to the initial allocation of allowances for the first compliance period starting in 2013 for industrial sectors not identified in Table 8-1 of the cap-and-trade regulation, and prior to the initial allocation of allowances for the second compliance period starting in 2015 for industries identified in Table 8-1 of the cap-and-trade regulation. We will update the Board annually on the status of the cap-and-trade program, including, to the extent feasible, information on shifts in business activity that may result in emissions leakage and changes in market share for covered entities and sectors.

C-148. Comment: Energy Independence Now (EIN) recommends that allowances for refineries and oil production require auctioning rather than CARB's proposed free allocation. This would allow a more competitive environment for emerging clean technology in the sector and potentially create an additional revenue stream for the development and adoption of these clean technologies. EIN acknowledges the fact that some free allocation in this sector is needed to prevent leakage. The Economic Allocation Advisory Committee found that only a small amount of free allowances may be needed to address leakage, but that further analysis is needed for the oil industry due to unique requirements for California fuel. Furthermore, the amount of free allowances distributed in this sector should not be based on the amount of petroleum produced or refined as currently proposed. This will act as an incentive for refineries and oil producers to increase their throughput rather than invest in efficient or clean technology. Rather, EIN recommends that allocations to the industry should be based on performance and that allowance value should be used to help transition the sector to more efficient and cleaner practices. (EIN)

> **Response:** We believe that without transition assistance, the competitiveness of industries that are both emissions intensive and trade exposed has the potential to be negatively affected relative to competitors that do not face similar GHG emission reduction requirements. An early emphasis on auction could hamper the ability of California sources to invest in low-carbon technologies. To incentivize investment and to minimize the potential for leakage, we believe a heavy emphasis on allocating free allowances in the program's early years before transitioning to heavy reliance on auctions would be more effective. As the commenter notes, allocation to industrial sectors based on the amount of annual production provides the incentive to continue in-State production. The program is specifically designed in this way to minimize emissions leakage.

C-149. Comment: We're the poster boy for leakage. We leaked two weeks ago when we shut down our refinery for economic reasons. First, we are very different from the major oil companies that most people are familiar with and who are competitors. California is already leaking capacity, and this does not include our plant. Well, where will the leakage go? China. India's capacity is growing similarly. Most people have the mistaken impression that oil refining is a lucrative industry because of the high cost at the pump. Unfortunately this price has little to do with refining profitability. What does is the difference between the price of products and the cost of raw materials. Refining profitability dropped significantly during the 2008 recession and has not returned. The high cost of crude oil has been hard on us. Now, if pass through of costs were possible for us, wouldn't we pass through these increased costs to our customers instead of shutting down? The major oil companies that are integrated do not need to make money on refining. With the high cost of crude, they can still be very profitable. Because of the recession, we urge you to consider the economic health of the industry's companies and especially the jobs affected in your rulemaking, and consider a form of hardship relief similar to what the EPA has. (PMTPETRO2, PMTPETRO3)

> **Response:** We recognize the potential risk of emissions leakage for industrial sectors that are emissions-intensive, trade-exposed with relatively limited cost pass through opportunities. And we designed a system for providing transition assistance to minimize leakage risks. As noted in the Staff Report, we are committing to monitoring how covered sectors, especially those who receive free allocation, address carbon costs once the program is in place. We have included features, such as periodic updating of leakage risks, to adjust free allocations.

C-150. (multiple comments)

Comment: Incremental emissions and employment leakage will occur from any amount of allowances auctioned to trade-exposed industry. The regulation correctly acknowledges the reality that California industry will be subjected to trade exposure as a result of the cap and trade program. California industry will be competing against global and interstate competition that are not similarly regulated, and therefore not subject to the same costs. Refiners and other industrial sectors will face a significant cost disadvantage with competing businesses outside of California. (BP)

Comment: We believe that ARB's conclusion about the refining industry as moderately trade exposed is not substantiated. Given the national, international, regional, and interstate competition for petroleum products that currently exists, it is clear that the refining sector is highly trade exposed. WSPA commissioned a study by Aspen Environmental consultants to evaluate the trade exposure of the refining sector in California. Aspen noted that ARB so far has used only national level data on value added for industries by NAICS economic sectors (refining is 3241), and only international trade data for California. However, data is available at the state level for most industries, including interstate trading activity. The interstate trade exposure (TE) index for California's entire manufacturing sector is 87 percent, well beyond the 20 percent threshold that ARB staff has proposed as "high exposure." Virtually every industrial sector exceeds the 20 percent threshold by this measure alone. Adding interstate trade to international raises the TE index for the refining sector to 26 percent. Specific to the petroleum refining sector, the national data sources used by ARB staff do not match with each other. The U.S. Census value of shipment and physical product appear to be 37 percent higher than the data reported by the U.S. Energy Information Administration and California Energy Commission. For these reasons, determining allowance allocations beyond the first cycle should be deferred until these issues can be addressed in greater detail. ARB should convene a work group in 2011 to review the most recent economic and trade information available and determine whether ARB staff's initial conclusions are supported. We recommend that ARB also incorporate interstate trade data in their analysis. ARB staff used import/export and shipment data from the U.S. Census Bureau to measure trade activity. Information on California trade from the Census Bureau is limited to the top 25 commodities imported and exported as well as the top 25 foreign trading partners. It does not track trade among states. While international competition is an important component of assessing trade exposure in various California industries, it is not sufficient. California industries also face competition from industries in other states throughout the U.S. that do not face the same stringent GHG regulations or even any GHG cap at all. (WSPA1, WSPA2)

Comment: The proposed regulation classifies petroleum refining as "medium risk" for emission leakage with significant implications for allowance allocation to the sector in the second and third compliance periods (see section 95870). We recommend classifying California refining as "high risk" for leakage due to trade exposure. The California refining sector is in direct competition with domestic and foreign refineries. These California operations would incur costs for refinery GHG emissions. Similarly, California refiners would be penalized for selecting heavy crude oils as per the LCFS program. Without appropriate protection, the fundamentals of the fuels market could force California refiners to curtail production or shut down. For instance, each 25 percent reduction in the allowance factor (high risk versus medium risk) adds approximately $150 million in annual compliance costs to the refining sector. Imports would likely increase from foreign refineries not required to hold allowances for refinery emissions. Large new refineries in India and the Middle East, with relatively low costs to operate are expected to have the capability to produce California-grade clean products for export to California as market conditions justify. Product imports to the U.S. east coast are large due to world pricing, and significant imports to the U.S. west coast are equally possible. The result would be lost jobs, reduced state revenues, and decreased fuel system security at no net benefit to the environment. CARB has appropriately classified the oil and gas sector as "high risk." CARB should classify the California refining sector as "high risk" for emission leakage through 2020, and issue allowances on this basis. Just as CARB has recognized that the State is subject to imports of crude oil cargoes, the state is also very much subject to imports of petroleum product cargoes. (CONOCO)

> **Response:** We believe our leakage risk determination for petroleum refining is supported by available data. We determine leakage risk using emissions intensity and trade exposure as two central measures. Our analysis is detailed in Appendix K of the Staff report. We analyzed emissions intensity data for all industrial sectors. We then selected natural break points in the emissions intensity spectrum. Industrial sectors are placed into the high, medium, low, and very low categories of emissions intensities based on these break points. For assessing trade exposure, we considered various approaches before choosing trade share as the metric to classify trade exposures.
>
> We recognize limitations of the data used. Per Resolution 10-42, we will continue to review information concerning the emissions intensity and trade exposure of different industries in California, and to recommend to the Board changes to the leakage risk determinations, if needed. We will update the Board annually on the status of the cap-and-trade program, including, to the extent feasible, information on shifts in business activity that may result in emissions leakage and changes in market share for covered entities and sectors.
>
> We will monitor for leakage as an integral part of cap-and-trade program implementation. Should ARB identify that leakage is occurring, we will develop appropriate responses to rectify them.

C-151. Comment: California's standalone actions on climate change will have a very negative impact on ConocoPhillips' operations in the state. The cost impacts will be significant and, depending on market reactions, may necessitate reduced operations that impact jobs and potentially increasing the State's dependence on gasoline and diesel imports. The cap-and-trade program as proposed, along with the State's LCFS program, disproportionately burdens our operations and California citizens. These combined actions will affect the viability of California refining, already trade-exposed to product imports, and adversely impact California consumers as cost of these programs become included in the price of goods and services. Transportation products should be excluded from cap-and-trade and CARB should classify California refining as "high risk" due to trade exposure. Absent the adoption of national and international climate frameworks that avoid economic dislocation and emissions “leakage”, state programs must move cautiously if at all. (CONOCO)

> **Response:** We recognize the potential impact on industrial sectors from the absence of GHG regulation outside of California. We believe the transition assistance and leakage protection feature of the cap-and-trade program is adequate to mitigate the potential impacts. Per Resolution 10-42, we will continue to review information concerning the emissions intensity and trade exposure of different industries in California, and recommend to the Board changes to the leakage risk determinations, if needed. We will update the Board annually on the status of the cap-and-trade program, including, to the extent feasible, information on shifts in business activity that may result in emissions leakage and changes in market share for covered entities and sectors. Transportation fuels are included in the program starting in 2015 after new reporting requirements have been in place for several years. We believe it is important to include transportation fuels in the program coverage in order to create a level playing field between energy types with respect to greenhouse gas emissions.

Miscellaneous

C-152. (multiple comments)
Comment: Energy-intensive industries need to have flexibility to allow incremental reductions in order to prevent leakage. (SDCHAMBER)

Comment: CARB's approach to classifying industries based on relative GHG intensity lacks an appropriate measure of proportionality and scale. The point-of-departure for CARB's leakage assessment is to identify and classify each industry's GHG emissions intensity. As noted by CARB, emissions intensity serves as a proxy for compliance costs, in which sectors with higher emissions intensities are likely to face higher compliance costs under the cap-and-trade program. As also noted by CARB, leakage risk is likely to be continuously increasing in emissions intensity. Due to “the excess administrative burden and technical difficulties,” however, CARB asserts that allowances could not be distributed as a continuous function of emissions intensity. Although CARB fails to identify the precise nature of the “excess administrative burden” and “technical difficulties,” it concludes that it is generally more convenient to establish discrete categories along the emissions intensity continuum. (CSCME2)

> **Response:** Each sector is associated with different levels of emission intensity. Assigning different assistance factors based on each sector’s emission intensity is technically difficult and administratively resource intensive. We

believe that our analysis is appropriate because it correctly captures different sectors' degree of emission intensity. Further, per Resolution 10-42, we are developing methods for implementing AB 32 that minimize administrative burden.

C-153. Comment: Aircraft maintenance service is an emission intensive and trade exposed sector with a high risk of leakage, we ask that ARB identify this sector. United Airlines San Francisco Maintenance Center is subject to California's cap and trade program primarily due to greenhouse gas (GHG) emissions generated from the production of electricity and thermal energy, and the combustion of fuels in test cells. However, the aviation maintenance services center (NAICS code 411190) was not analyzed in the leakage analysis. Many, if not all, cogeneration facilities that report based on their industrial host's NAICS code are listed in Table 8-1 and would receive free allowances to cover carbon costs associated with heat and electricity consumed on-site. Because the Maintenance Center is not identified as an industrial sector that is subject to leakage risk, no free allowances are provided to the Maintenance Center under the proposed regulation. We ask that ARB identify the aviation maintenance services sector as eligible for free allowances in Table 8-1. (UNITEDAIRLINES)

Response: We agree, and modified our leakage risk assessment accordingly.

C-154. (multiple comments)
Comment: ARB should consider making Ct in the product-based benchmark equation equal to one for industrial sectors in the "High" leakage risk category. For these sectors which are particularly sensitive to increased costs and competition from outside the jurisdiction of the cap and trade market, it will not be meaningful to offer 100 percent assistance or coverage with free allocation and yet indicate that this only applies to a fraction of the emissions that meet or exceed the industry's benchmark. These facilities should be covered completely to ensure that they are not put into a competitive disadvantage in the marketplace. (GPI)

Comment: The proposed regulation virtually guarantees that every industry, regardless of its leakage exposure, will immediately be placed at a competitive disadvantage, with the magnitude corresponding to at least 10 percent of its GHG compliance obligations. This cost disadvantage could be substantially larger depending on the extent to which indirect emissions costs are reduced through compensation from distribution utilities, as this policy mechanism remains largely undefined in the proposed regulation. CARB's proposed approach will impose costs on California cement producers that will not be faced by importers. To the extent that CARB believes that this approach is consistent with the mandate to minimize leakage, it is logical to presume that staff believes that such costs are insufficient to induce leakage. (CSCME2)

Response: In designing the system for allocating free allowances, we balanced the need for transition assistance and leakage prevention against meeting the AB 32 mandated GHG reductions. We believe our approach is balanced and is expected to be effective in achieving GHG reductions. It will provide California industries with adequate transition assistance, leakage risk protection, and incentive to innovate toward a low-carbon economy.

C-155. Comment: EDF recommends that in determining the risk of leakage (and therefore the appropriate allowance allocation), CARB take into account the amount of existing excess capacity in particular industries. (EDF1)

Response: While excess capacity is a very useful indicator to understand the relationship between supply and demand, at this point it is very difficult to obtain that information. We believe that using industrial activities as the indicator is appropriate for determining leakage risk and the calculation of allowances for allocation.

C-156. (multiple comments)
Comment: The imposition of a broader auction in the second and third periods will only increase leakage by imposing higher costs on industry. So long as California is not joined in the cap and trade program by other jurisdictions and California industry remains subject to competitive forces, this leakage risk is heightened and CARB should take every step possible to avoid it. (CMTA1, CMTA2)

Comment: Until a critical mass of states and countries adopt carbon policy that results in a similar cost of carbon, California should freely allocate 100 percent of allowances to trade exposed industry. Any less free allocation exposes California industry to incremental costs to which their competitors, both international and other states are not exposed. (BP)

Response: We are aware of the impact of the absence of cap-and-trade programs from other jurisdictions on California industrial sectors and designed a program to minimize the impact. Even though our allowance allocation system will transition into more reliance on auctions, we believe giving allowances for free in early years will provide sufficient transition assistance and incentives for industry to innovate and stay competitive against those outside of California. As noted in the Staff Report, we are committed to monitoring how covered sectors, especially those who receive free allocation, address carbon costs once the program is in place. In addition, for allocation purposes we are collecting product data from almost all sectors at risk for leakage. The data set from this collection will also serve as a key monitoring step in detecting leakage. We have included features, such as periodic updating of leakage risks, to adjust free allocations.

C-157. Comment: Small commercial and industrial customers (small business) deserve the same transition assistance as large industrial customers. ARB has indicated that in addition to providing allowance value to deter leakage of large businesses (business flight), free allowances would also be provided short-term to "provide a transition period to smooth market start-up." The same type of transition assistance should be provided to smaller commercial and industrial customers (under the 25,000 metric ton limit), so as to not discriminate against small business. Given the nature of rate regulation, allowances that are administratively allocated for this purpose can flow through to this class of customers. (SWGASCORP)

> **Response:** Free allowances are allocated to industries based on their emissions intensity and trade exposure, and this approach does not discriminate according to business size. Transition assistance is not necessary for industrial facilities emitting less than 25,000 CO_2e metric tons/year because they are not subject to a compliance obligation under the cap-and-trade program. Electrical Distribution Utilities are provided free allowances for the benefit of ratepayers in sufficient quantity to compensate ratepayers for the costs of the program. Transition assistance is not necessary for the natural gas industry because the industry will not be covered by the program until the second compliance period, which allows time for the industry to plan for inclusion. We are continuing to evaluate how to allocate allowances associated with natural gas. Furthermore, emitters that are below the threshold for inclusion in the program may opt-in to program requirements and receive free allowances based on their particular production activity.

C-158. Comment: The proposed factors to determine emissions leakage potential are largely based on US data and do not reflect Solar's business or California operations. The information presented on "Value of Shipments" and "Value added" metrics used for our classification appears to be based on broader industry data. It is not clear if ARB considered that more than 70 percent of Solar's products are sold to international customers. (SOLARTURBINES1)

> **Response:** We analyze all credible available data iteratively to classify industrial sectors for emissions intensity and trade exposure. We use the results of the classifications as two central measures for classifying leakage risks. In the absence of California data, it is necessary to use national data for the classification. The details of our analysis are presented in Appendix K of the Staff Report. A discussion of the strengths and weaknesses of the data used is included.

C-159. Comment: Currently the Draft Final Rules do not include the NAICS code 325199 (All Other Basic Organic Chemical Manufacturing) at all in the High, Medium or Low Leakage Risk category in Table 8-1. The fuel and steam use at Dow Pittsburg are largely categorized under NAICS code 325199. Dow conducted an analysis of onsite steam generation and onsite natural gas use in process heaters versus NAICS code applicability. Dow Pittsburg determined that 97 percent of our total boiler and process heater fuel use onsite in Dow equipment is classified under NAICS code 325199. Dow also determined that 98 percent of our steam consumption is classified under NAICS codes 325199 and 325188 (All Other Basic Inorganic Chemical Manufacturing). This steam is generated by Dow onsite and is also purchased steam from Calpine, also generated onsite. We also noted that one percent of Dow Pittsburg natural gas fuel use is classified under NAICS code 325320. Dow recommends that NAICS code 325199 needs to be added to ARB's Table 8-1 in the Final Regulation in the High Leakage Risk category. (DOWCHEM1, DOWCHEM2)

Response: We agree, and the regulation was modified as proposed.

Assessment of Leakage Risk

C-160. Comment: In Appendix J, the regulation states that the Industry Assistance Factor is essentially the ability an industry has to pass-on carbon costs. With low-cost competitors throughout the world, even a minimal increase in cost could displace certain market segments as demonstrated in the previously listed reports. (ACC2, ACC3)

Response: We want to clarify that the industrial assistance factor is based on the sector's leakage risk, which is derived from the sector's emissions intensity and trade exposure. The assistance factor is one of the factors used to calculate allowances for free allocation to assist industry to transition into our cap-and-trade program and prevent leakage risk. We believe our allocation strategy minimizes leakage. Per Board Resolution 10-42, we will continue to evaluate the risk of emissions leakage and make recommendations to the Board for any changes necessary to minimize the risk of leakage.

C-161. Comment: The proposed factors to determine emissions leakage potential are based on national data and are not necessarily indicative of California or local conditions. Of particular concern is that pharmaceutical and aerospace companies are identified as "low leakage risk", when in fact these two industry sectors are widely sought after by other states. (SDCHAMBER)

Response: We analyzed all credible data available iteratively in deriving emissions leakage risks for industrial sectors. In the absence of needed California data, national data was used for classifying trade exposures and emissions intensities. Per Resolution 10-42, we will continue to review information concerning the emissions intensity and trade exposure of different industries in California. We will recommend changes to the Board on leakage risk determinations, if needed, prior to the initial allocation of allowances for the first compliance period starting in 2013 for industrial sectors not identified in Table 8-1 of the cap-and-trade regulation, and prior to the initial allocation of allowances for the second compliance period starting in 2015 for industries identified in Table 8-1 of the cap-and-trade regulation. We will update the Board annually on the status of the cap-and-trade program, including, to the extent feasible, information on shifts in business activity that may result in emissions leakage and changes in market share for covered entities and sectors.

C-162. Comment: Assessing leakage risk is an inexact science at best and many CMTA members have expressed great concern about how their industries have been categorized. Because cost ramification of the determination is so high, we should be much more certain that the leakage categories and the industry members of each are valid. Moving forward with this scheme with the current level of analysis is fraught with political, legal and economic risk. (CMTA1)

> **Response:** We analyzed all credible data available in assessing emissions leakage risks for industrial sectors. We recognize that there are uncertainties in the determination. The assistance factor is 100 percent for all producers at the outset of the program, settling to a level of compensation needed to minimize leakage, based on our analysis, by 2018 in recognition of the uncertainties associated with a lack of publically available State-level trade data for all industries. Per Resolution 10-42, we will continue to review information concerning the emissions intensity and trade exposure of different industries in California. We will recommend changes to the Board on leakage risk determinations, if needed, prior to the initial allocation of allowances for the first compliance period starting in 2013 for industrial sectors not identified in Table 8-1 of the cap-and-trade regulation, and prior to the initial allocation of allowances for the second compliance period starting in 2015 for industries identified in Table 8-1 of the cap-and-trade regulation. We will update the Board annually on the status of the cap-and-trade program, including, to the extent feasible, information on shifts in business activity that may result in emissions leakage and changes in market share for covered entities and sectors.

C-163. (multiple comments)
Comment: Emissions leakage is a direct consequence of economic leakage, that is the relocation of output, jobs, investment, and other economic activity to jurisdictions that do not face comparable GHG regulations. (CSCME2)

Comment: In the absence of national and global GHG policies, California sectors will all be trade exposed. The best way to mitigate this exposure is 100 percent free allocations. The cost of carbon will be set by the direct measures adopted under AB 32 and the cost of purchasing offsets. In the absence of national and global policies, an auction of allowances will further and unnecessarily increase the costs of the program without providing additional environmental benefits, and perhaps lead to environmental degradation due to leakage of emissions and jobs to states or countries with less stringent environmental policies. To remedy this problem, CCEEB recommends that ARB establish a test to determine if an industry is trade exposed. The ARB's trade exposure test should rely on two criteria: (1) is there a federal program; and (2) is there linkage? Allocations should be evaluated every three years in relation to the trade exposure test and other market indicators, such as the reports and recommendations by an independent market monitoring committee. (CCEEB1, CCEEB2)

> **Response:** We recognized that California industrial producers compete in a global market and, in the absence of national and global GHG policies, could be competitively disadvantaged as a result of the regulation. We believe that industry assistance is necessary to provide a smooth transition into the cap-and-trade program for industrial sectors with competitiveness risks. The level of assistance provided will be high at the start of the program but decline over time

to a minimal level necessary to prevent emissions leakage as industrial sources adapt to a low carbon economy.

In designing our allowance allocation system to minimize leakage, we analyzed available data on emission intensity, trade exposure and cost pass-through ability, and approaches used by other existing and proposed greenhouse gas policies. Our leakage assessment will be updated periodically and assistance factors are already adjusted for the different compliance periods based on leakage risks. We are committed to monitor how covered sectors address carbon costs once the program is in place. We will work with covered sources and other interested parties to identify additional sources of information at the state level that could improve our ability to monitor leakage. Should we find that leakage is occurring despite the safeguards in the regulation, we will examine mechanisms to address leakage.

C-164. Comment: ARB's proposed rule includes provisions designed to address emissions leakage and avoid disadvantaging California business. The primary tool for addressing leakage is output-based allowance allocations for "Industry Assistance." The proposed rule includes formulas that determine the quantity of allowances allocated to industry participants in each year. Under these formulas, assistance will decline over time due to changes in the "assistance factor" and the "adjustment factor." In addition, ARB decisions about the "emissions efficiency benchmark" for each sector will also affect the extent to which industry assistance neutralizes the effect of the cap and trade system on firm competitiveness. Neither ARB's proposed Rule nor the ISOR indicate the criteria to be used in developing these benchmarks.

The quantity of allowances granted to firms in a given sector, as specified by these formulas, varies depending upon that sector's vulnerability to leakage. ARB faces several difficult challenges as it tries to identify sectors potentially vulnerable to leakage. A sector's vulnerability to leakage in the short- run and long-run can depend upon many factors, including market structure, industry cost structure, market trends, demand responsiveness and preferences, constraints on competition from other geographic regions, industry investment opportunities and constraints, and the magnitude of the regulatory cost or constraint. However, fully accounting for all of these factors not only requires significant data but requires analyses tailored to each industry's particular circumstances.

Faced with limited resources and data, ARB has proposed to use emissions intensity and trade share to measure vulnerability to leakage, while recognizing the limitations of these metrics. For example, the ISOR notes comments made by the Australian regulator regarding "the importance of supplemental qualitative analysis when trade share is used due to the uncertain indication of cost pass-through ability."

Because GHG and trade related metrics do not provide a perfect measure of an industry's vulnerability to leakage, some cap-and-trade programs propose that regulators may consider factors other than the formulas and conditions used to identify emissions-intensity and trade-exposure to identify vulnerable sectors. Under the EU ETS, the list of sectors “deemed to be exposed to a significant risk of carbon leakage” may be supplemented by taking into account the extent to which individual facilities can reduce GHG emissions or electricity use, future projections of market conditions, and firms’ profit margins. In Australia’s Carbon Pollution Reduction Scheme, sectors may apply for assistance by arguing that they have “a demonstrated lack of capacity to pass through costs due to the potential for international competition. Similarly, ARB has indicated that it will “continue to develop techniques to evaluate the trade exposure of various industries.

As ARB considers these alternative techniques, it may want to consider supplemental assessments reflecting both quantitative and qualitative information about a sector’s vulnerability to leakage. These assessments might better capture leakage risks for industries in unique circumstances. Use of such assessments typically requires clear and well- defined criteria and methodologies and transparent procedures for review to ensure that determinations are consistent across sectors, reflect objective, independent analysis and reflect true industry vulnerability. Ensuring adequate procedural safeguards can place an additional administrative burden on the program. Despite these complications, such assessments may be warranted given data limitations for measuring GHG or trade intensity at the state level, and may provide ARB with information on the extent to which its emissions-intensity and trade-exposure metrics have accurately captured leakage vulnerability of industries within California.

As ARB further analyzes how to most effectively address leakage, several issues are worth considering. First, prior efforts by regulators to design mechanisms to address leakage were developed within the context of national programs. However, leakage as a consequence of AB 32 may occur due to both international and interstate trade. As discussed in a prior paper, there is substantial reason to believe that trade vulnerability may be greater under these latter circumstances. Consequently, as ARB develops criteria for trade vulnerability, it might attempt to more explicitly account for these differences, particularly since it has relied largely upon metrics developed in the context of national programs addressing leakage from only international trade.

Second, as with other mechanisms used and proposed for addressing leakage, the level of assistance is insensitive to the level of allowance prices. However, the level of allowance prices is one of the primary determinants of vulnerability to emission leakage. Examining compliance costs in the petroleum refinery sector illustrates this issue. When allowance prices are $10 per MT, the additional costs on the petroleum sector refining would be roughly 1.0 cents per gallon. By contrast, when allowance prices are $85 per MT, the additional costs would be roughly 8.1 cents per gallon. By contrast, transportation costs for refined petroleum range from 3 to 12 cents per gallon depending upon the point of origination. Thus, the magnitude of the incremental costs faced by California business as a result of the cap and trade program depends closely upon actual allowance prices. In light of this sensitivity, ARB might consider mechanisms that adjust that rate at which allocations for Industry Assistance are phased out for depending upon the level of allowances prices. (ANALYSISGRP)

Response: The purpose of the initial allocation of allowances is to provide transition assistance and prevent leakage upon the start of the cap-and-trade program. We believe it is especially important, given current economic conditions, to provide regulated entities the opportunity to invest in low-carbon technologies. The commenter addresses shortcoming of data and analysis of leakage risks, and the complex interplay factors impacting the industrial economy. We agree that there are uncertainties in data and analysis, but we carefully and methodically considered all information available to develop the cap-and-trade program. We are committed to monitor throughout implementation to identify unintended consequences and take appropriate action to rectify them, if found. We believe the proposed regulation is designed to minimize leakage to the fullest extent feasible. In considering the level of allocation necessary to reduce the risk of emissions leakage moving forward, allowance price is one consideration. The example provided by the Analysis Group points to a useful point of consideration. Using the commenter's information on transportation costs of refinery products, if the petroleum refining industry is compensated at approximately 90 percent of costs when allowance prices are in the $15/ton range (1.5 cents per gallon of refined fuel), the amount of necessary pass-through to avoid leakage is less than 0.2 cents per gallon. This is well below the 3 to 12 cents per gallon required to bring these fuels in from elsewhere, according to the commenter. Therefore, no leakage is expected based on the allocation mechanism.

Assistance Factors Too High

C-165. Comment: Lower the assistance factors in the industrial sector. While we support CARB's efforts to prevent leakage by identifying industries that are at high, medium, and low risk and compensating them, we are concerned that the assistance factors are overly generous and will assign allowance value to industry profits at the expense of consumer benefits. (ENVENTREP1)

Response: We believe that the assistance factors for the industrial sector are at the appropriate level to help industry transition into the cap-and-trade program and to provide leakage protection to those sectors with high emissions and trade exposure. The allocation design will reward those who have invested in energy efficiency and GHG emissions reductions, and will encourage continued investment in clean and efficient technologies in the future.

Alternatives to Addressing Leakage through Allocation

C-166. Comment: CARB proposes to address leakage solely through allowance allocation. They have dismissed more effective approaches without sufficient cause or justification. Please consider the use of border adjustments to address leakage in the industrial sector, and provide a detailed proposal to combine allowance allocations and a border adjustment to provide maximum leakage protection. (CSCME2)

Response: We believe, at this point, there are insufficient resources to implement border adjustment. Per Resolution 10-42, we will continue to review the technical and legal issues related to implementation of a border adjustment to impose obligations on importers of cement that are equivalent to those faced by California cement manufacturers under the cap-and-trade regulation, and to implement such a provision, if it is feasible and necessary, to avoid leakage in the cement sector. We will continue working, with input from stakeholders, on the possibility of implementing border adjustment for maximizing leakage protection.

D. AUCTION

Bid Guarantee

D-1. (multiple comments)
Comment: Shell Energy believes that it is prudent for ARB to seek assurance that purchasers of allowances at auction have the financial capability to buy them. However, we believe that it is unnecessary to require investment grade credit rated companies to post bid collateral. Such guarantees are needlessly costly and time consuming.

We recommend that ARB establish credit threshold tables for investment grade companies based on their publicly reported credit ratings. These tables would provide maximum amounts that a qualified entity would be able to bid without posting additional collateral. The better the credit rating, the higher the credit threshold. If an entity wanted to bid for allowances with a value greater than its credit threshold, it would have to post collateral for any incremental exposure in the normal way. (SHELLENERGY)

Comment: Minimize unnecessary bureaucratic requirements. Investment grade credit-rated companies should not have to post bid guarantees. [pg 92 (i)] (CCEEB1)

Comment: Creditworthiness as demonstrated by a high bond rating from a rating agency should be allowed in lieu of a bid guarantee. Most municipal utilities carry bond covenants and restrictions that limit their ability to post assets as collateral plus the cost for a letter of credit is significant. For electric distribution utilities, LADWP's preferred alternative to the ARB's bid guarantee requirements is to rely on a high bond rating as the basis for creditworthiness such as "AA" or above to qualify an entity to participate in a quarterly auction. There are also creditworthiness provisions outlined in master agreements such as those available through the Western Systems Power Pool (WSPP) or Edison Electric Institute (EEI) that could be used as the basis for participation by utilities in a quarterly auction. (LADWP1)

> **Response**: We do not agree with these comments for two reasons. First, we needed a bid guarantee mechanism that would not result in very different auction participation costs for different covered entities. Second, we will be contracting with a financial services provider who must be able to access the guarantee instrument with minimal time and effort. The method proposed in the comment would require a lengthy and costly recovery effort by ARB, which might not be completed within the auction schedule.

D-2. Comment: The calculation of the bid guarantee results in excessive credit requirements for bidding. Section 95912(i)(2) places the amount of the bid guarantee at an amount that is “greater than or equal to the sum of the value of the bids submitted by the auction participant.” This can result in a bidder who places multiple bids at different price levels being required to pay a bid guarantee that exceeds the amount they would end up paying if the market cleared at the lowest price bid by the bidder (this would be the only instance where the bidder would be required to pay for all of its bids). Because the higher priced bids would actually be paid at the lower market clearing price, the bidder would never have a situation of needing to match all of the bid prices if they had bid in at different prices. We suggest a wording change to require the bid guarantee to cover the "maximum total cost for any possible settlement price of all bids submitted by the auction participant." (SMUD1)

> **Response:** We understand the use of the term “sum of the value of bids” in section 95912(i)(2) to be the maximum value as the commenter suggests, since (1) bids not awarded allowances have no value, and (2) in a single price auction the value assigned to a winning bid quantity is the auction settlement price. We do not believe a change is needed.

D-3. Comment: Compliance entities should be able to use the value of in-state physical assets and/or credit rating as bid guarantees. The requirement to provide the auction administrator with assurances in the form of bonding, cash, or a letter of credit is really unnecessary and burdensome for compliance entities with large physical assets in the state and/or who may be investment-grade, credit-rated companies. (BP)

> **Response**: We do not agree with these comments for two reasons. First, we needed a credit assurance mechanism that would not result in very different auction participation costs for different covered entities. Second, we will be contracting with a financial services provider who must be able to access the guarantee instrument with minimal time and effort. The method proposed in the comment would require a lengthy and costly recovery effort by us, which might not be completed within the auction schedule.

D-4. Comment: The Utilities are concerned that the bid guarantee election is more difficult for smaller utilities with less capital and credit. The Utilities believe that bids should be settled quickly so that any money, letter of credit, or other cash equivalent that is given for the guarantee is not tied up for extended periods of time. Furthermore, to protect these funds, guarantees should be placed in an escrow account separate from any funds of the State. In addition, the Utilities request additional guidance within the proposed regulation as to the timeline and process for settling the auction and reserve sales, including how winning bidders will be required to provide cash if they are guaranteed with a substitute, and when CARB will return the guarantee back to unsuccessful bidders. (MID1)

> **Response**: Bid guarantees will not be placed in any of the state funds. Instead, the guarantee instrument will be handled by a financial services administrator contracted by us, as described in section 95912(h). We will only require that the instruments are available until after the deadline for the auction participant to pay for the allowances. Once the auction participant has paid for the allowances it has been awarded, there will be no further need for the instrument, and it can be returned to the auction participant. We agree with the commenter’s request for guidance on the process and timeline. We will develop the procedures and

timelines for submission and return of financial assurance mechanisms with the financial services provider. We will provide guidance and training for participants prior to the auction and reserve sales.

Group Association on Purchase Limit for Opt-in Covered Entities and Voluntary Participants

D-5. (multiple comments)
Comment: CARB should impose a group limit on auction purchases for opt-in and voluntary participants. The proposed regulation creates an Auction Purchase Limit for individual entities participating in the allowance auctions. During the first compliance period, for covered entities and opt-in covered entities, the limit is set at 10 percent of the allowances; IOUs are not subject to a purchase limit; for all other auction participants, the limit is set at 4 percent. SCE strongly supports CARB's creation of these purchase limits to ensure that a few entities (particularly non-compliance entities) do not claim undue market power due to purchases at the allowance auctions. However, the possibility remains that a large group of entities can purchase enough allowances to push covered entities out of the market. Therefore, SCE recommends that CARB create an additional limit on the total number of allowances that non-covered entities, as a class, can purchase from the auction.

Based on SCE's internal analysis, it appears that the Auction Purchase Limit will always be less than the Holding Limit for voluntary and opt-in participants, and thus will likely be the limiting factor on the number of allowances these parties can purchase at auction. As noted above, voluntary and opt-in participants are limited in their individual purchases of the total allowances available at auction. However, the Auction Purchase Limit does not adequately mitigate the risk of inadequate allowances being available for compliance participants. If, for example, 5 voluntary participants and 2 opt-in participants all purchase allowances up to their auction limits, these participants could cumulatively purchase 40 percent of the available allowances in that auction, assuming the prices they bid were higher than the market clearing price. The remaining 60 percent of allowances would be substantially short of what compliance entities need to meet their obligations.

This would force compliance entities to purchase a large portion of their compliance burden in the secondary markets. Given that the markets will be aware of compliance shortfalls prices in these markets are likely to soar, which will cause an undue burden on electric customers. Thus, CARB should limit the total number of allowances that voluntary and opt-in participants can purchase in the auction as a class in order to provide adequate protection against covered entities being pushed out of the market due to market manipulation by non-covered entities. (SCE1)

Comment: The proposed regulation adopts a complicated and problematic design for the auction and sale of GHG allowances. As noted above, this auction design may lead to unintended consequences that CARB staff may not have foreseen when crafting the auction rules. For example, SCE supports the Auction Purchase Limits for individual entities, but without additional group limits on auction purchases, compliance entities may be unable to acquire sufficient allowances at auction. Entities without Cap and Trade compliance obligations could then drive up allowance prices with the knowledge that compliance entities are short. (SCE1)

> **Response:** We are allowing non-covered entities to purchase and hold compliance instruments to ensure that the market prices instruments reflect the likelihood that the price of instruments will increase over time. We expect that the covered entities will undertake the cheapest direct reductions early, undertaking more expensive reductions later. This increasing cost of direct reduction should lead to higher instrument prices over time. In an efficient market, the expectation that prices will be higher in the future should cause market participants to purchase and bank additional allowances early. This causes the prices to rise early in the program, signaling to market participants that they should be more aggressive in pursuing direct reductions.
>
> We are concerned that excluding financial participants would prevent the market from giving a price signal that reflects expected future increases in the cost of direct emission reductions. Covered entities may not have the financial ability to purchase and hold allowances for later compliance periods. If we exclude financial participants, prices may not reflect anticipated future scarcity, and covered entities will not receive the correct price signal supporting the need for additional current direct reductions. The correct price signal should lead to fewer price changes over time. If we accepted the proposed group limit for non-covered entities, it is possible that they would be unable to purchase enough allowances to generate the correct price signal.
>
> While it is true that speculative participants do not have compliance risk, they do run the risk of financial loss if they overestimate the rate of price increases.
>
> We agree with the calculations proposed by the commenter, but they apply only to a single auction. Should a covered entity be outbid at an auction, it can raise its bid price and quantity at the next auctions to make up for the shortfall.

Errata

D-6. (multiple comments)
Comment: Modify section 95911 (c)(2) as follows:
"the auction purchase limit in ~~(A)~~(1) does not apply. This subsection ~~(B)~~(2) shall not be interpreted to." (NCPA1)

Comment: Section 95911(c) discusses auction purchase limits. For purposes of clarity, SCE believes that within section 95911(c)(2), "(A)" and "(B)" should read "(1)" and "(2)." (SCE1)

Comment: Section 95911(c)(2) references the auction purchase limit in “(A).” PG&E believes that ARB intended to reference (1) instead of (A) at the end of that sentence and that ARB will amend this provision to reflect this. (PGE1)

> **Response**: We replaced all of section 95911(c), which corrected the reference error.

D-7. Comment: Modify section 95912 (j) as follows:
“At least 60 days prior to each auction the auction administrator shall publish ~~on~~ the following information.” (NCPA1)

> **Response**: We made this correction.

D-8. Comment: Section 95922 (a) and (b) refer to section 95930. However, that section does not exist. PG&E believes that ARB intended to reference section 95830 and that ARB will amend the regulation to reflect this. (PGE1)

> **Response**: We corrected the references.

Purchase Limit

D-9. Comment: CARB should seek broad participation in adjusting action purchase limits in the future. CARB has noted that it is only setting Auction Purchase Limits for the first compliance period and will set limits for subsequent periods in a later rulemaking in order to gather and learn from actual market experience. SCE strongly supports allowing CARB the opportunity to adjust the rules based on data gathered from early compliance years, as it should retain as much flexibility as possible in writing the current regulation. CARB should ensure that cap and trade market participants, particularly compliance entities, are actively involved in the next rulemaking process, as these entities will provide valuable information gained in early market experiences. Compliance entities should have adequate time and notice for comments and a thorough workshop process in order to properly inform CARB staff about their experience in the market during the first compliance period. (SCE1)

> **Response:** The comment is duly noted. We will continue our efforts to engage stakeholders in our rulemaking process in the future.

D-10. Comment: The proposed regulation sets an Auction Purchase Limit for covered entities and opt-in covered entities at 10 percent of the allowances offered for auction. Any Auction Purchase Limit must be set sufficiently high to provide reasonable access to allowances for obligated entities yet foreclose the opportunity for single entities to “corner the market.” Thus, IEP supports the concept of an auction purchase limit as a means to increase liquidity and participation in the individual quarterly auctions and mitigate against potential hoarding of allowances. What the appropriate limit should be is probably an empirical question based on reported emissions over time. We caution, however, against setting the limit at a specified percentage for the duration of the program. As obligated entities change over time, some will grow (through mergers, etc.) and an auction limit that may be correct for 2012 may be wholly misplaced in 2020. Thus, we recommend modifying the proposed regulation to allow revision of the Auction Purchase Limit over time as conditions change, subject to reasonable notice and opportunity to comment prior to adopting such changes. (IEPA)

> **Response:** We agree with the comment that the purchase limits should be set empirically over time to reflect changes in emissions resulting from merger or other factors. It is for this reason that we did not make this change apply past the first compliance period. In fact, we did change the regulation to raise the purchase limit for covered entities from 10 percent to 15 percent to reflect changes in emissions from larger entities due to changes in facilities and operating levels.
>
> Going forward, we expect that linking to WCI or to other emissions trading systems could also lead to changes in the purchase limit. Since these linking arrangements would take the form of new regulations with new purchase limits, staff concluded that setting a purchase limit now to last through 2020 would be premature.

D-11. (multiple comments)
Comment: The proposed regulation would apply the auction purchase limit to the first compliance period only, and the purchase limit for future compliance periods would be established in later rulemakings (ISOR, IX-72). CARB believes that the purchase limit is needed “to ensure that a few entities do not obtain market power through purchases at the auctions.” (ISOR, IX-72) NCPA agrees, however, NCPA believes that absent special circumstances that can be demonstrated by compliance entities, the purchase limits should apply throughout the term of the Program. The purchase limit should be set for the entire Program, and if, subject to a review of the Program it is determined that the limit should be modified, a subsequent rulemaking can be initiated to make the change at that time.

All of the reasons articulated by CARB to support sunsetting the purchase limit—developing a better understanding of the needs of larger compliance entities with additional data, more knowledge of a matured market as time passes, and greater understanding of the interactions between California’s program and the Western Climate Initiative (WCI) partners—are valid reasons to review the purchase limit amount for subsequent compliance periods. However, none of these reasons negate the need to include purchase limits as a market protection mechanism going forward. Accordingly, it would be far simpler—and safer—to include the purchase limit in the regulation for the entire duration of the Program, with the understanding that it—like any other provision that does not work when reviewed in a maturing program—will be changed for subsequent compliance periods. NCPA recommends modifications to section 95911 (c) as follows:

~~For auctions conducted from January 1, 2012, through December 31, 2014, t~~The share of allowances of any vintage year offered at any quarterly auction which may be purchased by one entity or a group of entities with a corporate association pursuant to 95914 shall be limited to less than. (NCPA1)

Comment: The Utilities agree that the purchase limit should be reviewed and appropriately adjusted for the later two compliance periods, as indicated in the ISOR (page IX-72). However, the Utilities believe that the purchase limit is a critical component of ensuring the operation of a sound allowance market and should be extended throughout the program. ARB would still have the ability to revise the limit in subsequent compliance periods to account for market adjustments and allowance distributions. (MID1)

> **Response**: We appreciate the concerns raised in the comments requesting ARB set purchase limits now for the length of the program. We understand that setting a level for the length of the program may give market participants a clear understanding of the market structure, giving them insights into future competitive conditions. Going forward, we expect that linking to WCI or to other emission trading systems could also lead to changes in the purchase limit. Since these linking arrangements would take the form of new regulations with new purchase limits, staff concluded that setting a purchase limit now to last through 2020 would be premature.

D-12. Comment: IEP is opposed to the exception to this policy as it relates to investor-owned utilities ("IOUs"). The proposed regulation would exempt the IOUs from the purchase limit because "entities do not receive a direct allocation that they can use for their own compliance needs" (Initial Statement of Reasons, p. II-38). IEP notes that IPPs, under the proposed regulation, "do not receive a direct allocation that they can use for their own compliance needs." Removing the purchase limit as it applies only to the IOUs has the effect of positioning the IOUs to acquire more allowances than they require and hoarding them for other purposes while limiting their availability to obligated entities such as IPPs. For example, it's conceivable that possession of allowances by the IOUs beyond what they need for their own compliance purposes would have value in bilateral negotiations between the IOUs and IPPs. By treating electric utilities owning electrical generation in a different manner than the treatment of other market participants such as IPPs, the proposed regulation, unless modified, would foster anti-competitive and potentially discriminatory outcomes. All parties should have equal access to allowances needed for compliance. CARB should ensure that the Allowance Purchase Limit applies equally to all parties participating in an allowance auction. CARB should delete the language in Section 95911(c)(2) that states that the auction purchase limit does not apply to IOUs. (IEPA)

> **Response:** We set the purchase limits based on data on larger emitters, taking into account direct allocations, to set a purchase limit that would allow all entities the ability to meet their compliance needs from the auction. We created the exemption from the purchase limit because (1) the IOUs must consign directly

allocated allowances, and (2) they may have to purchase allowances above the level of their direct emissions to cover emissions resulting from energy generation purchased under long term contracts. We also believe that the concerns that the exemption for IOUs will alter competitive conditions are addressed through the holding limit.

D-13. Comment: Section 95911(c)(2) (p. A-88) provides that the auction purchase limit does not apply to IOUs. The ISOR provides three reasons for this exclusion: IOUs may have large compliance obligations; IOUs must purchase the allowances they require at auction (or on the secondary market); and IOUs are regulated. These three reasons may also apply to POUs. Depending on their size, POUs may have large compliance obligations. They may have to purchase allowances they require at auction (or on the secondary market) if they do not take advantage of the section 95892(b)(2) option to have their administratively allocated allowances deposited into their compliance accounts. And they are closely regulated by their governing boards. Therefore, the exclusion from the auction purchase limit should be extended to all electrical distribution utilities, not just the IOUs. Modify section 95911(c)(2) as follows:

> For ~~investor-owned~~ electrical distribution utilities ~~receiving a direct allocation of allowances pursuant to 95892(b) and subject to the monetization requirement pursuant to 95892(c):~~ the auction purchase limit in subsection (~~A~~1) does not apply. This subsection (2~~B~~) shall not be interpreted to exempt ~~said investor owned~~ electrical distribution utilities from any other requirements of this article. (SCPPA1)

D-14. Comment: Section 95914(e)(1) (p. A-100) provides that the purchase limit applies to a group of entities with a corporate association. It should be clarified that this does not apply to a group electrical distribution utilities that are exempt from the purchase limit under section 95911(c)(2) (p. A-88) (with section 95911(c)(2) being expanded to exempt POUs as well as IOUs from the purchase limit as discussed in a previous comment). This needs to be made explicit because section 95911(c)(2) provides that the exemption "shall not be interpreted to exempt those entities from any other requirements of this article." Modify section 95914(e)(1) as follows:

> The total number of compliance instruments which may be purchased in a single auction by a group of entities (other than electrical distribution utilities) with a disclosed corporate association is limited pursuant to section 95911(c). (SCPPA1)

Response: We have not provided the POUs with the exemption, but we have addressed these concerns through modifications to the regulations. First, the purchase limit has been increased from 10 to 15 percent. Second, a revision to section 95892 gives the POUs the option to request the Executive Officer to place directly allocated allowances into the compliance accounts of facilities operated by POUs, Joint Power Agencies, or electrical cooperatives, rather than having them consigned. POUs who take advantage of this option would need to purchase fewer allowances at auction.

D-15. Comment: Section 95915(e) (p. A-103) provides for the application of the purchase limit to entities in bidding associations, but the drafting is unclear. Under section 95915(e)(1), the purchase limit will be applied to the bids submitted by the "recipient." However, if a purchaser is buying allowances on behalf of a recipient, the recipient may not enter any bids in the auction. Also, by referring to bids submitted by the recipient alone, section 95915(e)(1) would not include allowances purchased by a purchaser for a recipient in the recipient's purchase limit. According to the ISOR (at IX-102), the purpose of section 95915(e)(1) is to apply the purchase limit to the recipient and "not to the apparent purchaser." Section 95915(e)(1) needs to be revised to accomplish the stated purpose. Further, it is unclear how section 95915(e)(3) (p. A-104) is intended to operate. Section 95915(e)(3) refers to "the sum of bids submitted by the entity or entities in the bidding association designated as the 'recipient.'" However, recipients may not submit any bids themselves if the bidding function is assigned to entities designated as "purchaser" in the bidding association. (SCPPA1)

Response: This comment is no longer valid, as we have completely removed section 95915. Modifications to provisions in section 95914 governing disclosure of information on auction participation made section 95915 unnecessary.

D-16. Comment: The Utilities support the concept of applying auction purchase limits as set forth in the proposed regulation. However, the Utilities are concerned that unforeseen circumstances could result in the need for an amount of allowances exceeding a covered entity's purchase limit during the last year of a compliance period. The Utilities request that the proposed regulation include a provision authorizing the Executive Officer to grant exceptions to the purchase limit for good cause, on a case by case basis. Modify section 95911 as follows:

(c) Auction Purchase Limit. ~~For auctions conducted from January 1, 2012, through December 31, 2014, t~~<u>T</u>he share of allowances of any vintage year offered at any quarterly auction which may be purchased by one entity or a group of entities with a corporate association pursuant to 95914 shall be limited to less than:

(1) For covered entities and opt-in covered entities: ten percent of the allowances offered for auction<u>, provided, however, that upon a showing of good cause by a covered entity, the Executive Officer may grant a limited extensions of this limit during the final year of the Compliance Period where due to unforeseen circumstances beyond the entity's control the entity requires additional purchase limit to meet its surrender obligation</u>.

(2) For investor owned electrical utilities receiving a direct allocation of allowances pursuant to 95892(b) and subject to the monetization requirement pursuant to 95892(c): the auction purchase limit in (~~A~~<u>1</u>)

does not apply. This subsection (~~B~~2) shall not be interpreted. (MID1)

Response: POUs and covered entities receiving free allowances should not encounter situations where they need a number of allowances exceeding the purchase limit. In addition, IOUs do not have a purchase limit. We believe the revision raising the purchase limit to 15 percent, along with the provisions in 95892 allowing POUs to have directly allocated allowances placed in the compliance accounts of entities from whom they purchase electricity is adequate to accommodate their needs.

D-17. (multiple comments)
Comment: MSCG is not opposed to purchase limits, although we think they are better held in reserve, to be imposed if market problems are detected, and purchase limits are determined to be an appropriate solution, rather than be part of the “Day 1” auction design. (MSCG2)

Comment: Section 95911 establishes a 10 percent auction purchase limit that applies for all auction participants except Investor-owned Utilities (IOUs). WPTF appreciates that ARB is trying to prevent market manipulation. However, we challenge the premise that a purchase limit is in fact necessary. Participants in the allowance auctions will be subject to existing state and federal laws prohibiting unfair competition. Those statutes permit criminal prosecutions in some instances and provide the basis for significant civil penalties. Further, the proposed limit fails to take into consideration the fact that the other regulated entities, beyond IOUs, will also have large compliance obligation. Because independent power producers will have to purchase all their allowances through auction or the secondary market, the proposed auction limit would greatly constrain the ability of some entities to procure sufficient allowances. Under these circumstances, WPTF recommends that ARB initiate its auctions without artificial market limitations. If it later becomes apparent that existing unfair competition laws do not adequately address any perceived market irregularities, then ARB could consider a purchase limit, but at a higher level, such as the 25 percent adopted under RGGI. In any event, there should be no exemption for IOUs; such an exemption has the potential to further tilt the playing field in favor of utility-owned generation with no real benefit to the efficient operation of the market. (WPTF)

Response: We believe a purchase limit is an important instrument to ensure that a few entities do not obtain market power through purchases at the auctions. We disagree with three issues raised by the comment. First, state and federal laws prohibiting unfair competition cannot prevent the exercise of market power. They only attempt to recover damages after events occur. This is exceedingly difficult as we would have to identify how a market manipulation affected all market participants. Legal proceedings under those laws are lengthy, resource intensive, and would create greater uncertainty for the market.

Second, we have revised the purchase limit after consultation with covered entities, raising it from 10 percent to 15 percent. Data on emissions, allocations, and expected auction volumes indicate this level is sufficient. Raising the purchase limit to 25 percent is not necessary and could allow speculators to acquire enough allowances at the end of the first compliance period to give them market power.

Third, we created the exemption from the purchase limit because (1) the IOUs must consign directly allocated allowances, and (2) they may have to purchase allowances above the level of their direct emissions to cover emissions resulting from energy generation purchased under long-term contracts. We also believe that the concerns that the exemption for IOUs will alter competitive conditions are addressed through the holding limit. Finally, the speculative activities of the IOUs are subject to rules created by the CPUC.

D-18. (multiple comments)
Comment: Calpine would recommend that the auction purchase limit for covered entities during the first compliance period generally be kept at 10 percent of the total number of allowances available any given auction, but with an opportunity for any covered entity or group of covered entities with a corporate association to exceed this limit, so long as its total purchase of allowances of any vintage year does not exceed 125 percent of its average annual verified emissions during the preceding three calendar years, plus, for any entity with less than three years' reported emissions data, an additional amount that represents a reasonable estimate of the entity's anticipated emissions during that calendar year. This would allow large affiliated entities, such as Calpine, to satisfy their anticipated compliance obligation through purchases at auction, while still avoiding the potential for covered entities to engage in market manipulation by purchasing an amount of allowances grossly in excess of their anticipated compliance obligations for any calendar year. The 125 percent limitation for entities with three years' reported emissions date would provide sufficient flexibility to accommodate annual variation in a facility's dispatch, as well as some amount of increased dispatch that might be expected to occur as a result of a cap and trade program for more efficient generating units, such as Calpine's fleet. Additionally, the additional amount for entities with less than three years reported emissions is intended to provide a covered entity with the opportunity to purchase allowances for newly commissioned facilities.

Section 95911. Format for Auction of California GHG Allowances.

Auction Format.

(c) Auction Purchase Limit. For auctions conducted from January 1, 2012, through December 31, 2014, the share of allowances of any vintage year offered at any quarterly auction which may be purchased by one entity or a group of entities with a corporate association pursuant to 95914 shall be limited to less than:

(1) For covered entities and opt-in covered entities: ten percent of the allowances offered for auction~~.~~ provided, however, that the Executive Officer may authorize any covered entity or group of entities with a corporate association to purchase an amount of allowances in excess of ten percent during any auction so long as such entity's or group of entities' total purchase of allowances of any vintage year does not exceed 125 percent of the entity's or group of entities' average annual verified emissions during the preceding three calendar years, plus for any entity with less than three years reported emissions data, an additional amount that represents a reasonable estimate of entity's anticipated emissions during that calendar year.

~~For investor owned electrical utilities receiving a direct allocation of allowances pursuant to 95892(b) and subject to the monetization requirement pursuant to 95892(c): the auction purchase limit in (A) does not apply. This subsection (B) shall not be interpreted to exempt investor owned electrical utilities from any other requirements of this article~~

(A) Any covered entity or group of covered entities with a corporate association that anticipates purchasing more than ten percent of the allowances offered for auction during any quarterly auction shall submit a statement to the Executive Officer within thirty (30) days prior to the auction date identifying the covered entities for which it anticipates purchasing allowances, the total average annual emissions for such entities with three years' reported emissions data and the anticipated emissions for any entities with less than three years' of reported emissions. The statement shall be accompanied by any supporting information and the certification set forth at section 95894(b)(6). If the Executive Officer does not find that the covered entity's or group of entities' anticipated emissions for any entity with less than three years' reported emissions represents a reasonable estimate of the entity's anticipated emissions during that year, the Executive Officer shall notify the entity within seven (7) days prior to the auction date.

(2) For all other auction participants: four percent of the allowances offered for auction. (CALPINE1, CALPINE2)

Comment: The proposed regulation sets an auction purchase limit for covered entities and opt-in covered entities of ten percent (10 percent) of the allowances available in any auction conducted during the first compliance period. 17 C.C.R. section 95911(c)(1) (proposed). While Calpine understands the need to prevent market manipulation, Calpine's covered entities in California could realistically need to purchase more than 10 percent of available allowances just to cover their compliance obligations, depending upon the amount of allowances that the POUs consign for auction. By subjecting large affiliated generators such as Calpine to an auction limit that could realistically be lower than their total compliance obligation, the proposed regulation could force such large generators to obtain allowances from the secondary market or the Allowance Price Containment Reserve at a significantly higher cost than available from the general auction. As a result, the proposed auction limit could place large generators such as Calpine at a significant competitive disadvantage. (CALPINE1, CALPINE2)

> **Response**: We have addressed the issues raised in the comment through consultations with covered entities. This has led us to raise the purchase limit from 10 percent to 15 percent, which should address the problem of fluctuations in emissions level for the first compliance period. ARB will be mindful of the comment when it revises the purchase limit for the second compliance period.

D-19. Comment: The draft indicates that the purchase limit rules are to be in place through 2014. However, no indication is made of what will happen after that date. Is it accurate to assume they will be removed? Will the Executive Officer formally reassess and re-determine after a certain amount of real world experience? The rule should state what the intent is for times after 2014. (MSCG2)

> **Response**: We will set the limit for subsequent periods in a later rulemaking. We are proposing this approach for three reasons. First, we will have a better understanding of the compliance needs of larger entities when new reporting data become available for the expanded scope of the program during the second compliance period. Second, we recognize that the market will take time to develop, and it may be necessary to revise the limit based on actual market experience. Third, we intend to link with WCI jurisdictions at some point, but WCI has not arrived at a decision on purchase limits. We may have to revise the limit to account for the size distribution of covered entities in the WCI.

Corporate Association

D-20. (multiple comments)
Comment: The auction purchase limits related to direct and indirect corporate associations must be modified for regulated electric utilities. Section 95914 of the proposed regulation requires entities registered pursuant to Section 95830 to disclose direct and indirect corporate associations with other registered entities. The proposed regulation further provides that the total number of compliance instruments that may be purchased in a single auction by a group of entities with a disclosed corporate association is limited pursuant to Section 95911(c), and that entities that are a part of a corporate association may allocate shares of the purchase limit among themselves.

These provisions are entirely infeasible for California's investor-owned electricity distribution utilities. There are long-standing affiliate transaction restrictions imposed on the utilities by the CPUC and FERC. These restrictions generally limit the types of transactions that a regulated utility may enter into with its unregulated affiliate, as well as the transfer of non-public transmission and other proprietary information to affiliates that may create the opportunity for preferential treatment, unfair competitive advantage, or cross-subsidization.

Specifically, as a utility, SCE is subject to the CPUC's "Affiliate Transaction Rules for Large Energy Utilities" ("CPUC Affiliate Rules") that were most recently revised in Decision ("D.") 06-12-029. SCE is also subject to the CPUC's rules concerning non-tariffed products and services, including the CPUC-approved Gross Revenue Sharing Mechanism adopted in D.99-09-070, as well as some of the Holding Company Conditions set forth in D.88-01-063. The CPUC Affiliate Rules, as well as the CPUC's holding company decision, also require that SCE and its affiliates maintain structural separation, and ratepayer indifference to transactions, between the utility and its affiliates. In implementing these principles, the CPUC has concluded that utilities must maintain complete procurement planning independence from their affiliates. Finally, SCE is subject to the FERC Standards of Conduct and FERC affiliate restrictions. SCE has implemented the Affiliate Rules and developed comprehensive compliance plans and manuals to ensure compliance with these rules. SCE has developed an affiliate compliance website, employee training programs, affiliate expertise, personnel, and other internal infrastructure to manage its compliance. SCE has also made organizational structural decisions and changes based on the Affiliate Rules. Collectively, these Affiliate Rules require a very high level of separation of business activities between regulated utilities (such as SCE) and unregulated affiliates (such as Edison Mission Group ("EMG")), that operate in California and nationwide in unregulated wholesale electricity markets. For example, CPUC Affiliate Rules require that transactions between a utility and its affiliates shall be limited to tariffed products and services, to the provision of information made generally available by the utility to all market participants, and to Commission-approved resource procurement by the utility. Further, the rules require that the sale or purchase of goods, property, products or services be made generally available by the utility or affiliate to all market participants through an open, competitive bidding process.

Due to such regulatory firewalls, SCE will be accruing its own GHG compliance obligation without any knowledge of the corresponding compliance obligations of its unregulated affiliates. SCE may not discuss, let alone act in concert, with EMG regarding its electricity purchases and sales activities in the California wholesale markets. When the cap-and-trade program begins, SCE will not be allowed to share with EMG its forecast of emissions based on the projected emissions from its power plants and emissions related to electricity imports; nor will it be allowed to coordinate its participation in CARB's allowances auction with EMG. SCE and other EMG companies, such as Edison Mission Energy, will be expected to separately register with CARB and will be expected to separately report their emissions, to the extent their respective emissions need to be reported pursuant to CARB's mandatory reporting regulations.

Given these regulatory screens, SCE believes that it should have its own Holding, Limited Use Holding, and Compliance Accounts, which will be distinct and separate from any such similar accounts of its affiliates. SCE also believes that it should transfer compliance instruments to its own compliance account, and that any such transactions will be separate and uncoordinated with similar transactions by its affiliates. SCE and its affiliates will also separately submit verification statements.

In light of rigid and long-standing regulatory firewalls between regulated and unregulated affiliates in the electricity industry, CARB's proposed regulation to apply a single limit to the combined purchase by a group of entities who have a direct or indirect corporate association is simply not workable for such entities and must be modified. CARB needs to create an exception from this regulation that exempts regulated electric utilities from having to comply with a combined Auction Purchase Limit jointly with its unregulated affiliates.

Indeed, it seems CARB itself has acknowledged this issue and has created precisely such an exemption in its proposed regulations for Holding Limits. Section 95920(b)(6) states that "the application of the holding limit will treat holdings of entities with a corporate association pursuant to section 95914 as being held by a single entity unless existing law or regulation prohibits coordinated market activity by the associated entities, including the transfer of instruments between accounts controlled by associated entities." However, Section 95914(e)(1), in laying out the "Application of the Corporate Association Disclosure to the Holding Limit," claims that the "total number of compliance instruments which may be purchased in a single auction by a group of entities with a disclosed corporate association is limited pursuant to section 95911(c)." SCE seeks confirmation that Section 95920(b)(6) allows regulated entities such as SCE to be free from joint Holding Limits with its corporate associate(s). Additionally, SCE requests that CARB provide entities with existing regulated barriers to trade—such as investor-owned electric distribution utilities—an exemption from the joint Auction Purchase Limits as currently expressed in Section 95914(e)(1). (SCE1)

Comment: While SCE recognizes the need for disclosure of corporate affiliations to prevent market manipulation, the application of Holding Limits and Auction Purchase Limits to associated entities as if they were one entity is unworkable for regulated electric utilities like SCE that are subject to firewalls and other corporate affiliation regulations. (SCE1)

> **Response**: The comment is correct in its assessment that the purpose of the language in the original section 95920(b)(6) was intended to address the issue of state and federal restrictions on market coordination by affiliates. After consultations, we have replaced this language with new section 95833(a)(4) to ensure that existing state and federal laws and regulations are not violated. Placement in section 95833, which contains the rules determining when corporate associations exist, ensures that the exemption applies to any rule involving corporate associations.

D-21. Comment: Section 95915(a) (p. A-102) requires the disclosure of bidding associations with entities registered in GHG emissions trading systems ("ETS"), "in Canadian provinces to which California has linked," implying there is no need to disclose bidding associations with entities registered in GHG programs in other states, such as New Mexico. The ISOR does not include the limiting reference to Canada, and there does not appear to be any reason to require disclosure of bidding associations with entities registered in Canadian programs but not programs in other states. Modify this section to eliminate the reference to Canadian provinces as follows:

> Entities registering for the auction pursuant to section 95912 must disclose bidding associations with other entities also registered into the California cap and trade system or registered into one or more GHG ETS programs ~~in Canadian Provinces~~ to which California has linked. (SCPPA1)

> **Response**: This comment is moot, as we have completely removed section 95915. Modifications to provisions in section 95914 governing disclosure of information on auction participation made section 95915 unnecessary.

D-22. Comment: Section 95914 needs to be modified to recognize the CPUC's affiliate transaction rules. This section requires the identification of Direct and Indirect Corporate Associations. California public utilities can disclose names of parent and affiliated companies, but have limited knowledge of the unregulated business affiliates. Utilities subject to the jurisdiction of the CPUC must comply with rigorous affiliate compliance rules in their dealings with their unregulated affiliates. Identification of the names of the parent and affiliated companies may be provided, but information sharing or any economic transactions between the regulated and unregulated entities are subject to stringent regulations. The public policy behind these rules is to protect utility ratepayers from being negatively impacted, economically or otherwise, by any actions of a utility's unregulated affiliates. Unregulated affiliates are not to be provided any information or economic benefit from the utility that could give such unregulated affiliate any information that is non-public, or would put it in a preferential position in any transactions or dealings. Any proposed rules and regulations that would aggregate or transfer benefits, responsibility or penalties between regulated and unregulated companies would likely be in contravention of CPUC rules or regulations and need to be eliminated from any proposed ARB regulations. Add a new section 95914 (c)(4) as follows to ensure consistency with CPUC affiliate rules:
(c)(4) Any registered entity subject to affiliate compliance rules promulgated by state or federal agencies shall not be required to disclose information or take other action in contravention of such rules. (SEMPRA1)

> **Response:** We agree with the comment, and the appropriate text has been added to section 95833(a)(4).

Confidentiality

D-23. Comment: The regulation should be revised to eliminate the prohibition (section 95912(d)(2)) on an auction qualifier revealing its Qualification Status. (MSCG2)

> **Response:** We have removed the text at issue and replaced it with new section 95914 (d)(2), which gives clearer rules for disclosure of the use of an agent.

Auction Guideline

D-24. (multiple comments)
Comment: There should be more definition how an auction system would work, and auctions should be delayed until the program is well tested. (SDCHAMBER)

Comment: NCPA is concerned that despite the level of detail regarding disclosure and registration, as well as pre-and post-purchase reporting activities, there are several programmatic shortcomings that should be improved before implementation. This includes more detailed information regarding closing and accounting procedures and timelines, and transaction costs associated with the mandatory participation in the CARB administered auction. The proposed regulation needs to ensure that operations will be conducted in an expeditious and transparent manner. (NCPA1)

> **Response:** We have placed in the regulation all of the rules which auction participants must follow. The procedures for submitting the required information for certifications and for the processing of financial transactions will occur after we have contracted for the provision of auction and financial services. In addition, the contracts with the service providers will include provisions for extensive system testing before the market begins operation.

D-25. Comment: Section 95911(d)(5) (p. A-90) provides a complex process for resolving tie bids by assigning random numbers to each bundle of 1,000 allowances. A simple, familiar pro rata process should be used instead. The ISOR states that a pro rata process was rejected on the grounds that it could result in awards of allowances in bundles of less than 1,000, "which would add to the auction's complexity." However, it may be more difficult to use the complex random-number process outlined in section 95911(d)(5) than to use a pro rata process and award allowances in bundles of less than 1,000. If desired, the numbers of allowances awarded under a pro-rata approach could be rounded up or down to an appropriate round number. (SCPPA1)

> **Response**: We disagree with the assertion made in the comment that the random number process is more complicated. We adapted the procedure from the one used by RGGI. We concluded that the approach employed by RGGI has been successfully implemented, which should be an important criterion in selecting a procedure. In addition, during stakeholder meetings leading up to release of the regulation, most stakeholders considered RGGI to be a successful implementation and urged us to follow successful implementations when they are available.

Limited Use Holding Account

D-26. Comment: Allowances from the Limited Use Holding Accounts should be sold before allowances or offsets from suspended or revoked accounts. In order to ensure that Covered Entities in good standing are able to monetize their allowances, NCPA recommends that the order in which consigned allowances are used to fulfill winning bids be revised. CARB proposes to fulfill winning bids with allowances from the suspended or revoked accounts "because ARB may need to return unsold allowances to their source accounts [which is] not possible for allowances from closed, suspended, or revoked accounts." (ISOR, p. IX-69) However, rather than penalize Covered Entities that are looking to monetize their allowances by ranking allowances from limited use holding accounts second, the allowances from suspended or revoked accounts could be placed into the CARB Auction Holding Account until the next quarterly auction. Also, it is appropriate for the number of allowances that are drawn from each entity's account to be proportionate. NCPA recommends modifications to section 95911 (b)(3) as follows:

(A) The auction operator will fulfill winning bids with allowances from consignment sources in the following order:
(i) allowances consigned from limited use holding accounts pursuant to subarticle 5 ~~allowances consigned to auction pursuant to section 95910(d)(2~~);
(ii) allowances consigned to auction pursuant to section 95910(d)(2) ~~allowances consigned from limited use holding accounts pursuant to subarticle 5~~;
(iii) allowances directly allocated by ARB to auction pursuant to subarticle 8.
. . . .
(B) When there are insufficient winning bids to exhaust the allowances from a consignment source in (A) above, the auction operator will sell an equal ~~number~~ percentage of allowances from each consigning entity in that source. (NCPA1)

> **Response**: We believe it is important to exhaust the allowances consigned to auction pursuant to section 95910(d)(2) first, so that violations could be settled in a timely manner. These allowances will be sold from accounts that are suspended or closed, so if they remain unsold at auction there will be no account to which they could return. We expect that the number of allowances sold from closed accounts will be very small, especially considering that each auction in the first compliance period will have nearly 20 million allowances for sale. Therefore, giving allowances from closed accounts priority in the order of sale should have no significant effect on the number of consigned allowances sold.

Unsold Allowances

D-27. Comment: Further, the bidding process for the allowances in the Allowance Reserve is confusing and inefficient and will lead to higher costs and increased risk for compliance entities. (SCE1)

> **Response:** While we believe the original language on the bid process was clear, we do agree that it may result in an unnecessary amount of risk for bidders trying to obtain the number of allowances desired. We have revised the bidding process in section 95913, allowing bidders to specify a maximum willingness to pay for allowances and allowing bids to be fulfilled from the lowest-priced tier from which allowances are available. This should provide greater certainty that bidders will obtain the allowances they need without having to purchase more than they intended.

D-28. Comment: While SCE endorses unlimited banking of allowances, the Proposed Regulation is currently unclear as to the extent a covered entity may bank allowances when combined with Holding Limits and Auction Purchase Limits. SCE seeks clarification from CARB on this point. (SCE1)

> **Response:** We understand the term "unlimited banking" to mean that there is no time limit for holding a compliance instrument. It does not refer to holding an unlimited number of allowances. Therefore, there is no conflict between unlimited banking and a holding limit.

D-29. Comment: Section 95911(b)(4) (p. A-87) provides for allowances that are unsold at auction to be transferred to the highest-price tier in the Allowance Price Containment Reserve Account. SCPPA opposes having tiers in the Allowance Price Containment Reserve Account. However, if the allowance reserve must contain tiers, unsold allowances sent to the reserve should be added not to the highest tier but to the lowest lowest-price tier that has not yet been exhausted and closed. This will reduce the risk of allowances being transferred to a tier of the reserve that is never accessed. The ISOR states, at IX-70, that the highest tier was chosen "because it is possible that all of the allowances in the lower tiers may be sold, at which point ARB will close those tiers to further sales." This objective can be achieved by transferring unsold allowances to the lowest-price tier that remains open. (SCPPA1)

> **Response:** This comment is moot since we have revised the regulation so that allowances remaining unsold at auction will be returned to the Auction Holding Account. They will be re-auctioned after two consecutive auctions have achieved an auction settlement price above the Auction Reserve Price.

D-30. (multiple comments)
Comment: NCPA recommends that the unsold CARB held allowances not be placed directly into the highest level of the Reserve Account, as contemplated in section 95911(b)(4). Rather, those allowances should be placed back into the CARB Auction Holding Account (defined in section 95831(c)(2)), or at a minimum, the allowances should be used to repopulate the first tier of the Reserve Account. (NCPA1)

Comment: Section 95911(b)(4) states that allowances designated by ARB for an auction that remain unsold go to the highest tier in the reserve. PG&E strongly recommends that these allowances instead go back to the auction account and be made available at the next auction. Furthermore, PG&E understands that this language does not pertain to the "advance auction" allowances. Advanced auction allowances that remain unsold will go back to the auction account. PG&E requests that ARB add language to clarify this provision. (PGE1)

Comment: In addition, CARB should not require unsold, unallocated allowances to be transferred to the Allowance Reserve. (SCE1)

Comment: Finally, placing unsold allowances in the Allowance Reserve will needlessly increase long-term compliance costs. This could create an incentive for compliance entities to purchase many more allowances in early auctions than they need for compliance. If covered entities fear that unsold allowances will quadruple in price as a result of being placed in the Allowance Reserve, they will likely bid for much larger purchases in early auctions than necessary and plan to bank those allowances for later use. This behavior will create an artificial demand for allowances in early auctions with the potential to artificially inflate prices in the early allowance market overall. (SCE1)

Comment: The Allowance Reserve is intended to operate as a cost containment mechanism. The current design uses the Allowance Reserve to reduce supply in the allowance market and drive up prices. In order to provide real long-term cost containment, CARB should not reduce the supply of allowances in the auction. Sustained low allowance prices in the cap and trade should be welcomed as a signal that regulated entities are able to secure compliance at the lowest possible cost. CARB should not see this as an opportunity to arbitrarily increase allowance prices. (SCE1)

Comment: Unsold allowances should remain in the auction process and should not be transferred to the allowance reserve. The proposed regulation requires non-allocated allowances that are unsold in the auction to be transferred to the Allowance Reserve. This decision lacks a sufficient basis in economic efficiency or environmental impact. Given AB 32's mandate to reduce GHG emissions at the lowest possible cost, CARB should treat allowances designated for auction by CARB that are unsold from prior years in the same manner as non-allocated allowances from the current period by placing them in the quarterly auction, rather than the Allowance Reserve. (SCE1)

Comment: In order to avoid such an artificial price increase, CARB should roll over all unsold allowances to the next auction in the same manner as the allowances consigned to auction. (SCE1)

Comment: ARB includes several provisions aimed at achieving AB 32's 2020 GHG target that the lowest possible cost. However, other provisions inadvertently raise costs, or create the risk of higher costs. Re-consideration of these provisions could lower the cost of achieving AB 32 GHG targets. First, the proposed rule moves allowances that are not sold in the allowance auction to Tier 3 of the reserve. Instead, costs could be reduced by shifting unsold allowances to the next auction. If economic and or market circumstances change such that allowance prices rise, these allowances would be unavailable to help satisfy demand, thus raising costs until allowance prices rise to the Tier 3 price triggers. (ANALYSISGRP)

Comment: Transfers of allowances into the allowance price containment reserve holding account should be modified. Section 95831(4) establishes an allowance price containment reserve account, and states that allowances allocated by ARB that remain unsold at auction and allowances used to fulfill an entity's excess emissions obligation pursuant to section 95857(c) will be transferred to this account. SMUD suggests two modifications to these provisions.

First, allowances that remain unsold in a quarterly auction should be returned to the Auction Holding Account unless the unsold allowances are from a vintage at least one year prior to the auction in which they remain unsold. Unsold allowances in one auction do not necessarily imply that subsequent auctions will also have unsold allowances, particularly with lumpiness in allowance allocations and in investments that reduce need for allowances. Here, and in section 95991, the regulations should be modified to keep unsold allowances in the Auction Holding Account until it is reasonably clear that they are not required in current auctions. Transferring to the Allowance Price Containment Reserve Holding Account prematurely simply is a recipe for ratcheting up allowance prices unnecessarily. (SMUD1)

Comment: Allowances not sold at auction should be returned to the auction holding account rather than the highest allowance price containment reserve account. Section 95911(b)(4) states that allowances unsold at auction will be placed in the highest allowance price containment reserve account. This represents an unnecessary price escalation that appears based on the faulty assumption that if allowances remain unsold in one quarterly auction, it implies that they may not be needed for sale in the next or subsequent auctions. In fact, due to lumpiness of emission reducing investments and perhaps unequal amounts of allowances available for sale in each auction, as mentioned above, it is not clear that unsold allowances at the floor price in one auction will not be necessary in the next auction in order to keep cost-containment a priority. Forcing small amounts of allowances to be transferred from a $10 value to a $50 value during times of low demand will undoubtedly result in greater utilization of the allowance price containment reserve. ARB should aspire to make the usage of the allowance price containment reserve the exception, rather than driving the market toward its use through arbitrary rules which remove low priced allowances in favor of reselling at much higher prices when supply of allowances becomes tight.

SMUD suggests that allowances that remain unsold in a quarterly auction should be returned to the Auction Holding Account unless the unsold allowances are from a vintage at least one year prior to the auction in which they remain unsold. In short, the regulations should be modified to keep unsold allowances in the Auction Holding Account until it is reasonably clear that they are not required in current auctions. (SMUD1)

> **Response:** We agree that the allowances remaining unsold at auction should return to auction rather than be placed in the Allowance Price Containment Reserve (Reserve). We have made the change to the regulation in several places, including section 95911(b)(4) which governs the handling of unsold allowances. The allowances will be re-auctioned after two consecutive auctions have achieved an auction settlement price above the Auction Reserve Price.
>
> We resolved the concern that returning unsold allowances to auction would continue to depress auction prices by adding new section 95911(b)(4). Unsold allowances would be returned to the auction holding account. They would be

redesignated for auction after two consecutive auctions reach an auction settlement price above the Auction Reserve Price. In addition, the number of these allowances returned to auction must represent less than a 25 percent increase in the number of allowances being auctioned. These rules will ensure that whenever the market appears oversupplied allowances will be held out of the auction until the oversupply is corrected.

D-31. Comment: In justifying this treatment of unsold allowances, CARB staff claim that adding unsold allowances to the next quarterly auction will simply sustain excess supply in the auctions. That is not the case for several reasons. First, the cap consistently declines over the nine years of the program. Since the cap declines annually, supply scarcity can be expected to increase over time, and CARB does not need to create artificial scarcity by removing allowances from future auctions. Second, covered entities and voluntary participants will not be entering the market in set patterns. Auction participation patterns are inherently lumpy. While some participants may engage evenly, many will buy or sell in one auction, but not the next. Simply because an entity may be in a long position in one quarter is no reason to assume it will maintain that long position in subsequent quarters. Moreover, there is no reason to arbitrarily increase the price for those allowances from the auction settlement price to the reserve price. As a result, it is unreasonable to assume that excess supply in one auction will remain in any future auction. (SCE1)

Response: We agree that the allowances remaining unsold at auction should return to auction rather than be placed in the Allowance Price Containment Reserve (Reserve). We have made the change to the regulation in several places, including section 95911(b)(4) which governs the handling of unsold allowances. The allowances will be re-auctioned after two consecutive auctions have achieved an auction settlement price above the Auction Reserve Price. We disagree with the assertion made by this comment that there can be no systematic oversupply of allowances to a market. We note that oversupply has characterized the initial years of both RGGI and the EU ETS. This has occurred due to the uncertainty inherent in any long-term forecast of the level of economic activity, which determines the demand for allowances. Reducing the rate at which new allowances enter the market could result in a meaningful carbon price signal more quickly than a declining cap. A large over- allocation could result in an oversupply that could be drawn down very slowly if we rely solely on the declining cap. While the end result of both approaches would eventually be the same, we will have lost the benefit of a correct carbon price signal for as long as the imbalance remains uncorrected.

On the second point, many covered entities have been very clear that they intend to match the timing of allowances purchases to their emissions as much as possible. This rationale is behind many of the concerns covered entities have expressed concerning speculation and market manipulation.

Auction

D-32. Comment: All entities that have a reasonable means to recover the costs of GHG allowances ought to be required to participate in the allowance auction to obtain needed allowances for compliance. With regard to the electric sector compliance obligation, IPPs and IOUs are required to access allowances through the common auction format. IEP strongly supports this approach. On the other hand, POUs are uniquely provided the option of receiving free allowances placed automatically in their Compliance Account or in their Limited Use Holding Account for eventual auction (irrespective of the fact that they have a means of cost recovery for any allowances they are obligated to purchase). This approach unnecessarily treats the POUs differently than other obligated entities within the electric sector, in spite of the fact that the POUs have a reasonable means of cost recovery (i.e. through their rate structure). The impact of this differential treatment may be unknown, but increases the risk that the differential treatment afforded one subgroup of the electric sector advantages unavailable to others. IEP recommends modifying the Proposed Regulation to require all obligated entities that have a reasonable means of cost recovery to acquire the allowances they need for compliance purposes through a common auction format. (IEPA)

> **Response:** We understand the concern; however, POUs and IOUs operate differently with respect to electricity generation. POUs generally own and operate generation facilities that they use to provide electricity directly to their end-use customers. In order to minimize the administrative costs of the program to the POUs, and recognizing that directly allocating the allowances to the POUs does not distort their economic incentive to make cost-effective emissions reductions, we determined that it would be prudent to allow POUs to surrender directly allocated allowances without participating in the auction process. IOUs, on the other hand, have contracts with electricity generators that do not afford the IOUs the same level of control over the capital investments and operating decisions of the generation facility. We are concerned that the terms of these contracts could be adversely affected by allowing the IOUs to directly surrender allowances on behalf of their counterparties, which could lead to some foregone cost-effective emissions reductions. Instead, by requiring the IOUs to surrender the allowances at auction, the electricity generators will be sure to have a strong incentive to pass their GHG costs back to the IOUs, who will then be able to use their share of the auction revenue to reduce the ratepayer burden in a manner that is consistent with the goals of AB 32.
>
> In considering the exact amount of value to allocate to each local distribution utility, we took a cost burden approach. The framework was formed by holding a series of public meetings and with input from stakeholders. Our working consensus was laid out in the regulation. If you would like to view the presentations for these public proceedings please visit: http://www.arb.ca.gov/cc/capandtrade/meetings/meetings.htm#publicmeetings.

D-33. Comment: Section 95892(b)(2) (p. A-83) allows POUs to have the Executive Director place their allocated allowances in either their limited use holding accounts or their compliance accounts. SCPPA supports this provision for the reasons set out in the ISOR at II-32. Unlike investor-owned utilities ("IOUs"), POUs such as the SCPPA members generate a significant proportion of the electricity they sell and should not be required to submit all their allocated allowances to auction. (SCPPA1)

Response: No response is needed.

D-34. (multiple comments)
Comment: The auction system will create a bidding war between entities that will be limited in the price they can pay for allowances and utilities and other industries that can pay a significantly higher price because they have the ability to increase prices to consumers. This will lead to GHG reductions by forcing the shutdown of facilities that are unable to compete in the auction market. (AGCOALITION)

Comment: ARB should revise the proposed rule to eliminate the auction as the trading mechanism and institute a free trading platform that encourages least-cost solutions to the allocation of allowances. (HOR)

Comment: The auction process is inefficient. No regulated entity will know what the prices are, or what prices are required to successfully bid for and obtain allowances. So, they will learn in each auction. This is a very slow learning curve and leads to a limited ability to plan ahead. Moreover, as the aggregate emissions approach the cap, the prices that are bid will be wildly unpredictable, and many market participants may be unable to pay enough to obtain allowances they need for past operations. At the end of the process, in normal economic times, there will be more buyers than sellers, and the auction process will simply break down. (HOR)

Response: We believe that an auction system is the fairest and most transparent way to distribute allowances and will allow for broad participation and minimize opportunities for manipulation. Over time, our program will transition toward a greater reliance on auctioning, which will help maximize incentives for continued investment in clean and efficient technologies and provide revenue that can be reinvested for public benefit. We'll also create a market surveillance committee to ensure that market manipulation, which could create uncertainties, are detected in a timely manner. In addition, our penalty provisions contain strict penalties for market manipulation.

D-35. Comment: The proposed regulation may inadvertently prevent electric distribution utilities from selling allowances in the first quarterly auction of each year. Section 95910(d)(4) notes that allowances consigned to auction at least 60 days prior to the regular quarterly auction will be offered for sale at that auction. Section 95910(a) notes that an auction will occur on the twelfth business day of each calendar quarter, except for the very first auction, which is to be held on February 14, 2012. However, pursuant to section 95870(c)(1), the Executive Officer is not required to allocate allowances to electric distribution utilities until January 15 of each calendar year, after the deadline for consigning allowances to the first quarterly auction of each year. PG&E understands that ARB is aware of these timing issues and is working to change the dates as appropriate. (PGE1)

Response: We revised the schedule contained in the regulation for allocation, auction, and reserve sales. The new schedule should accommodate the concern expressed in the comment.

D-36. Comment: The "Advance Auction" program approach, which is beneficial to the establishment of a forward curve. The further into the future that a forward curve can be established in the market, the easier it is to hedge positions and finance project developments, whether in transformative technologies, emission reducing investments associated with existing infrastructure, or new construction of general purpose production facilities that will incur compliance obligations. (MSCG2)

Response: No response is needed.

D-37. Comment: The Utilities are unclear as to how future budget years will be distinguished for their separate auctions, and whether it will be done by year, compliance period, or otherwise. The Utilities request additional clarification of subsection 95910(c) to state what the Utilities understand to be CARB's intent that there will be separate auctions held each quarter. (MID1)

Response: Allowances from future vintage years are auctioned separately from current vintage allowances for each auction. For example, auctions in 2014 will feature separate auctions of allowances from 2014 and 2017.

D-38. Comment: ARB should make available a greater number of future-vintage allowances to help complying entities manage compliance costs. PG&E urges ARB to amend the proposed regulation to allow for auctioning of a substantial number of future-vintage allowances, so that complying entities can manage costs over time. Under section 95870(b) and 95910(c)(2), ARB will auction 2 percent of the 2015 allowance budget in 2012, 2 percent of the 2016 allowance budget in 2013, and so on. This is a step in the right direction, but a small step. No allowances of the 2013 and 2014 vintages will be auctioned in 2012, and 2 percent of the 2015 allowance budget is less than 8 million allowances. PG&E recommends that a significant quantity of future vintage allowances be made available through the auctions to effectively manage compliance costs and volatility. PG&E requests amendment of section 95870(c)(1) so that complying entities can execute approved hedging plans. The goal is to enable hedging by increasing market liquidity through orderly, gradual auctioning of substantial numbers of allowances prior to their vintage years. (PGE1)

Response: We agree and increased the advance auction amount from two percent to 10 percent.

Schedule

D-39. (multiple comments)
Comment: The Utilities recommend that the timing of reserve sales be split equally between quarterly auctions to provide covered entities with a sufficient amount of time to transfer compliance instruments into their compliance accounts and to assess needs before participating in the reserve sale. The Utilities recommend reserve sales occur 45 days following each quarterly allowance auction and modifying section 95913 as follows:

> *(c)(3)(B) Subsequent sales shall be conducted ~~three weeks~~ 45 days after each quarterly allowance auction pursuant to 95910.* (MID1)

Comment: As currently proposed, the submittal date for the various documents required to participate in the reserve sale is one week following each quarterly auction. The Utilities are concerned that this presents too little time for a covered entity to fully assess their need from the reserve and to develop the required bid guarantee documents. Thus, the Utilities propose an extra week be allowed for covered entities to submit the required documents. Please note that if CARB elects to change the timing of reserve sales to 45 days following each quarterly auction, as the Utilities propose in our comments to subsection 95913(c)(3)(B), the proposed change for subsection 95913(e) as follows, is no longer necessary.

> *(e) Submission of Bids to Purchase. At least ~~two~~ one week~~s~~ prior to the scheduled sale, a covered entity shall submit to the reserve sale administrator*:(MID1)

> **Response**: We changed the timing of the reserve sales to six weeks after each auction, as the commenter suggested.

D-40. Comment: We would also like to address frequency of auction and allowances. We believe that a more frequent auction is needed in the later years of the program to assure liquidity. We propose that you increase the auction frequency from quarterly to every two months. (CHEVRON1)

> **Response**: We are also interested in the possibility of more frequent auctions. We will consider this option as part of a future rulemaking with a full public process. During our stakeholder meetings in 2009 and 2010, we heard concerns from a number of stakeholders about the burden in time and cost to auction participants of more frequent auctions. We will explore the possibility in future rulemakings, keeping in mind the potential burden on stakeholders.

D-41. Comment: The timing of the first auction should be advanced to provide necessary allowance price discovery for electricity market in advance of January 1, 2012. Although the first surrender of allowances by capped entities is not required until May 2014, electricity generators will need to include the cost of allowances in bid prices for electricity as of January 1, 2012, when the first compliance period begins. Until a secondary market for compliance instruments develops, auctions will be the only means available for price discovery of allowances. Because the first auction is currently scheduled for February 2012, generators would have little direct information on which to base their assessment of the allowance price component of the power production for the January-February period. Given that generators need to ensure that the power price they receive is sufficient to recoup their allowance costs, earlier auctions will enhance allowance price transparency, and therefore eliminate market uncertainty that could cause prices to be higher than necessary. WPTF therefore recommends that the first auction be moved up to the last quarter of 2011. (WPTF)

> **Response**: We acknowledge the concern and have revised the first auction date to be further ahead of the compliance period start date.

Consignment Auction

D-42. Comment: CARB should clarify the role of industrial covered entities in consigning to auction. The proposed regulation requires clarification as to how allowances that are directly allocated will be treated once distributed. Section 95831(a)(3) of the proposed regulation creates a Limited Use Holding Account for entities that qualify for a direct allocation of allowances to consign their allowances to auction, but does not state how this Limited Use Holding Account will be populated. In Section 95870, it appears that the direct allocations for both public utilities and industrial covered entities will be transferred to the individual Holding Accounts of those parties. Yet a few sections later, the proposed regulation states that direct allowances to IOUs are placed directly into their Limited Use Holding Accounts, while POUs have a choice of placing their allowances in either their Compliance Account or their Limited Use Holding Account.

Section 95891 of the proposed regulation governs direct allocation of allowances to industry for “Industry Assistance.” This section lacks any discussion of which account—the Limited Use Holding Account or the Holding Account—the allocated allowances will be placed. As noted above, Section 95870 states as a general matter that allowances directly allocated will be transferred to individual Holding Accounts, which implies that industrial covered entities are not required to consign its allowances to auction, nor use them directly for compliance. This raises the question of whether industrial covered entities will have Limited Use Holding Accounts, and if so, what purpose those accounts will serve. Because of this inconsistency, SCE requests that CARB clarify the role that industrial covered entities will play in the auction and whether they will be required to consign any of their allocated allowances to auction. (SCE1)

> **Response**: Section 95921(d) states clearly that only entities with limited use holding accounts may consign allowances to auction. Section 95892 (c) further specifies that IOUs are required to consign free allowances to auctions. We believe the regulation is clear that industrial covered entities are not subject to consignment auction provisions.

Auction and Sales Procedures

D-43. Comment: Deadlines should be established for ARB decision-making processes to provide entities with a degree of certainty. Modify section 95912(l)(1) and (2) as follows:
(1) Certify whether the auction was operated pursuant to this article *within 5 days*;
(2) After certification, immediately direct the auction operator to. (CCEEB1)

> **Response:** We disagree with the comment. The rule specifies the process clearly enough to provide certainty for auction participants. The time to process auction transactions will depend on workload and the processes used by the contractors conducting the auction and financial transactions according to industry best practices.

D-44. (multiple comments)
Comment: In addition, the bidding process for the Allowance Reserve is confusing, inefficient, and will lead to higher costs and increased risk for compliance entities. A bidder in need of additional allowances from the Allowance Reserve must submit bids for a quantity of allowances from each tier, but the total must not exceed their unmet compliance need for that year. Moreover, because the bidder will not know whether that tier will be fully subscribed through bids from other covered entities, there is uncertainty about whether it will receive the bids it submitted. As a result, the bidder may choose to bid in a lower tier than the price he is willing to pay, risking that that tier will not be oversubscribed. This situation where bidders attempt to beat the system could be avoided by simplifying the Allowance Reserve. Bidders should be able to bid in their willingness to pay, and all bids should be met starting at the lowest reserve price, increasing to the next tier if bid quantities exceed the allowance quantity in the lowest tier.

An improved auction design could mitigate, if not eliminate, these uncertainties. For example, CARB could simplify the bidding process by allowing the unmet need from one tier to carry forward as a bid into the next lowest tier. Bidders should bid at their willingness to pay ($40, $45, or $50) and the market should clear at the lowest bid available. For instance, if bids are made for less than one-third of the Allowance Reserve, then all allowances from the reserve should be sold at $40. If the number of bids exceed one-third of total allowances, then all bids made at $40 should be fulfilled at $40, and those remaining bidders (at $45 or $50) should get the remaining $40 allowances pro-rated, and fill the remainder of their bids at $45. This bidding mechanism is consistent with the process used in the general auction, where bidders pay the settlement price even if their maximum bid was initially greater than the settlement price. (SCE1)

Although SCE advocates for bids to roll down into the lowest available tier, should a tier be over-subscribed, the bids should not roll up into the next tier. Market participants bid only their willingness to pay, and should not be forced to pay more than this due to a shortage. A market participant may bid into the $40 tier of the reserve, but have a reduction measure available to them at the cost of $43/ton, and therefore be unwilling to pay $45 per allowance. Therefore, when a tier is oversubscribed, a bidder should receive a pro rata reduction in allowances from its bid, 50 and the shortfall should not carry over to a higher-priced tier as the Proposed Regulation currently requires. Doing so could mitigate price uncertainty while eliminating uncertainties as to quantity (except in the case where the Allowance Reserve is completely exhausted). (SCE1)

Comment: ARB should consider the following modifications to its proposed mechanism for selling Reserve allowances:

1. Allow each buyer to submit a maximum quantity of allowances that it is willing to purchase at each Reserve sale; and
2. Automatically reduce bid quantities if a bid would lead the buyer to exceed its Holding limit.

These modifications would address problems that may arise with the proposed Reserve sale mechanism due to the potential that a buyer receives only a portion of her bid for allowances in Tiers that become exhausted in the current sale. These potential problems are best illustrated through an example. Suppose a buyer wishes to purchase 100 allowances up to the prices of the current Tier 2 price (e.g., $60 per MT). As illustrated below, each of her options for submitting bids raises problems that the first modification resolves:

Option 1: Bid for 100 allowances from the Tier 1 Reserve. If the Tier 1 Reserve becomes exhausted during the auction, she receives only a fraction this bid and purchases less than 100 allowances.

Option 2: Bid for 100 allowances from the Tier 1 Reserve (at $53 per MT) and for 100 allowances from the Tier 2 Reserve. She is guaranteed to purchase at least the 100 allowances she needs, but likely purchases more than she needs, and, moreover, may end up paying for higher priced Tier 2 allowances when Tier 1 allowances are still available.

Option 3: Bid for 100 allowances from the Tier 2 Reserve. She likely gets the 100 allowances she needs (and no more), but must unnecessarily pay for most costly Tier 2 Reserve allowances to ensure she gets the right quantity.

By contrast, with the proposed modifications, she is able to purchase exactly the quantity of allowances desired at the lowest price (i.e., her share of Tier 1 allowances and enough Tier 2 allowances to give her a total of 100 allowances).

Another problem arises if bids exceed buyer holding limits. Returning to the example, suppose the buyer’s account is 150 allowances below her holding limit, and she receives 80 allowances from her Tier 1 bid. If her Tier 2 bid is also for 100 allowances, then her entire bid will be rejected since it would exceed her holding limit. Instead, ARB should simply reduce the bid amount to 70 allowances (=150 – 80) to allow the buyer to meet their demand for allowances up to their holding limit. (ANALYSISGRP)

> **Response:** We revised the sales procedure after receiving a number of comments similar to this. In the new process, each bidder will submit a maximum willingness to pay and a quantity of allowances to be purchased. We will fill the bid from the lowest-priced tier with allowances available. This removes the need to make separate bids to each tier, which is the source of both overpaying and overbuying. This procedure also prevents the conflict between the bids and the holding limit.

D-45. Comment: In addition to the primary cost containment mechanism of using offsets, CCEEB supports an allowance reserve as an insurance policy against events such as unexpected market dynamics or difficulties obtaining ARB-approved offsets. We believe that the regulatory process may be too time consuming to respond in a timely manner and that relying on the emergency trigger creates undue disruptions and is unwarranted when it can be handled in a less draconian manner through preplanning. CCEEB recommends that ARB adopt a process to backfill the reserve before it is completely depleted. The refill mechanism should trigger once the reserve is 50 percent depleted to bring more supply into the market, recognizing that use of the reserve indicates scarcity in the market and potential liquidity problems. (CCEEB1, CCEEB2)

> **Response**: In its Resolution 10-42 of December 16, 2010, the Board directed us to monitor the depletion of the reserve and to make recommendations for corrective action. While the commenter is correct in pointing out that the regular regulation adoption process is long, we have the authority to implement regulations on an emergency basis on a shorter timescale.

D-46. Comment: We support use of an allowance reserve for cost containment but continue to be concerned that the design be objective, transparent and avoid creating a balloon payment by borrowing from the future and therefore shrinking supply. The allowance reserve, as proposed, is back loaded with the largest portion supplied by future allowances, 7 percent borrowed from the final compliance period. To balance the reduction in available allowances across the program, offsets limits for individual facilities have been raised from 4 percent to 8 percent. It's important to note that while the allowances are fully fungible instruments, the use of offsets is an option that a facility may choose not to utilize. If facilities do not use all of their allowable offsets in every year, then they are removed from the program, making it more punitive than it needs to be to meet the required emissions reductions. (CHEVRON1)

> **Response:** The use of offsets is a cost-containment method that is left to the discretion of the covered entity. It may use them or not. If they choose not to use offsets, it does not imply that the system is more punitive.

D-47. Comment: Compliance entities need transparency on the allowance allocations, reserve allowance supply, and cost cap triggers so that they can plan appropriately and develop optimal compliance strategies. (CHEVRON1)

> **Response:** The regulation contains the allowance allocation methods. The regulation specifies the prices for purchasing allowances from the reserve. There is no cost cap trigger, only the reserve. Therefore, the regulation is clear on these points.

D-48. Comment: The allowance window or allowance reserve must be designed to provide sufficient reserve liquidity. The design must include unfettered access to reserve allowances whenever market prices reach levels that make it necessary to reduce allowance prices below the collar ceiling price. Even if reserve allowances are available in sufficient supply, they cannot effectively provide a mechanism to mitigate costs if they are not accessible to entities that require them. (CHEVRON1)

> **Response:** The Reserve may be accessed quarterly, plus twice in the year after the end of the compliance period. This gives the covered entities the access they need.

D-49. Comment: We believe that the functionality of the reserve is tied to the source of the allowance supply. We cannot recommend supplying the reserve from either current or future allowances since both ultimately shrink supply and unnecessarily drive up market prices. (CHEVRON1)

> **Response:** Diverting allowances to the reserve does not automatically raise market prices, because of the simultaneous increase in the offset use limit by the amount being diverted to the reserve.

D-50. Comment: An allowance reserve funded by allowances from current or future periods with prices set artificially—and without the use of offset credits—is fundamentally flawed. (CHEVRON1)

> **Response:** The commenter does not say why it is flawed. We believe that the reserve meets the policy goal of providing a buffer supply at known prices to the market. We chose this approach because it provides more price certainty than would an auction. We have increased the offset use limit as much as possible while protecting the AB 32 goal of achieving reductions in California.

D-51. Comment: We recommend that the allowance reserve be backfilled in the third compliance period with offsets. We recommend that the reserve be available at all times and rather than artificially setting prices for the allowance reserve, ARB should develop policies that are tied to the market itself. Finally, we are concerned that unsold allowances from the quarterly auctions would be automatically placed in the allowance reserve because this will reduce liquidity and drive up costs unnecessarily. We recommend that unsold allowances be returned to the following auction. We recommend that the offsets limits be expanded to apply across the entire program rather than one year, and that facilities be allowed to sell their offset options. We are attaching separate comments on the allowance reserve provided by the Analysis Group. (CHEVRON1)

Response: The comment makes several points and we respond in the same order. Foremost, we cannot replenish the reserve with offsets because we do not have the authority to use auction or reserve sale revenue for that purpose. The approach would also complicate ARB's role as the market operator, since ARB would then become a market participant.

The reserve serves as a source of allowances between auctions. Having continuous reserve sales would increase the administrative burden of the program on both ARB and market participants, since we would have to conduct reserve sales at the same time we are conducting auctions.

We set the reserve prices at a level we expect to be above the most likely market outcomes. We did this in part to minimize the effect of the reserve on market efficiency. We also never intended the reserve to be a price ceiling or to actively manage market prices. Instead, we intended it to be a temporary buffer in case our expectations of the cost of meeting the cap were incorrect. The reserve would give staff time to modify the program to correct the problem.

We agree with the comment's proposal to send allowances remaining unsold at auction back to future auction rather than to the reserve. We changed section 95911(b)(4) to include the new procedure governing when unsold allowances would return to auction.

The depletion of the reserve in itself may not be an indicator of a potential market issue. Therefore, we did not make a change that would require an increase in the offset usage limit by backfilling the reserve with offsets in the third compliance period.

The regulation requires that offsets account for eight percent of an individual entity's emissions over a three year period. We did not allow the carryover of unused offsets within this time frame to ensure that emission reductions are being achieved by capped sources throughout the life of the program. Keeping it to the compliance period allows some flexibility by giving three years to total emissions, but still requires that emission reductions are coming from within capped sectors in all years of the program.

Allowance Reserve

D-52. Comment: Section 95913 is excessively ambiguous because it is much more complicated than it should be and requires clarification. The allowance reserve will be fairly large compared to quarterly sales of allowances in the auction since it is made up of the equivalent of 4 percent of allowances from 36 auctions. Accordingly, it would be far simpler to fill the excess need of compliance entities from the Price Containment Reserve if the price ceiling is reached in the auction and there is excess demand at the price ceiling. If compliance entities requested 10 MMT more than available at the ceiling price, the added 10 MMT would come from the Price Containment Reserve. The price ceiling would be the same as the Tier 1 level until it was exhausted, then the ceiling price in the following auction would increase to the Tier 2 level. Such a procedure would avoid a second auction and the complex rules in Sections 95913(e) and (f). (SEMPRA1)

Response: The comment about the ambiguous sales procedure is moot because we have revised the reserve sales process. We disagree with the comment on awarding allowances to auction bids above the tier prices. Entities will have adequate opportunity between auctions to purchase the allowances they need.

D-53. Comment: NextEra Energy supports ARB's use of the Allowance Price Containment Reserve defined in section 95913 of the regulation. It provides another source of procuring allowances for entities that incur a compliance obligation. (NEXTERAENERGY)

Response: No response is needed.

D-54. Comment: One of the requirements to utilize this pool of allowances however states participants "hold no compliance instruments in their holding accounts or limited use holding accounts." One reason for the inclusion of this provision is to ensure that entities using this mechanism for obtaining allowances do not profit from the sale of the allowances purchased from the reserve. This restriction is not necessary. There are other ways to ensure that any allowances purchased in this manner are used for compliance only. The emptying of accounts is not necessary and should be removed from the regulation.

NextEra Energy feels the emptying of all holding accounts in order to purchase allowances from the reserve causes more problems than it solves. For instance, will allowances with future vintages need to be retired? Also, the partial surrender of annual compliance obligation could trigger the need to go to reserve to make up any shortfall. Emptying entities holding accounts could effect the hedging positions taken for future compliance obligations. The Allowance Price Containment Reserve should be available to meet short term compliance obligations as needed by entities with a compliance obligation or to be used for long term speculation in anticipation of escalating allowance prices. In short, this requirement of emptying holding accounts does not maximize cost containment and could actually result in a cost escalation in future compliance periods.

One way to accomplish the same goal is to move the allowances purchased from the reserve directly to the retirement account of the purchaser or to tag the allowance as ineligible for transfer to another entity. Entities that have a compliance obligation need the flexibility to bank allowances obtained from various sources in order to fully realize any cost containment provided by the reserve. This flexibility benefits consumers by allowing entities with a compliance obligation to spread the risk associated compliance over time. (NEXTERAENERGY)

> **Response**: We evaluated the concern and removed the purchase requirements on the accounts' remaining allowances.

D-55. Comment: However, we are concerned that the reserve will be insufficient to contain costs if the market is short, not because of a temporary event but due to unforeseen systemic issues. Through discussions with ARB staff, we understand that the intention would be to change the cap and trade regulation should use of the cost containment reserve indicate a structural supply/demand problem. While we understand the need for market-based programs to be amended over time to reflect changes in technology/economic conditions, such changes should be rolled out in a predictable and methodical way and not as a result of market /regulatory panic over a depleting cost containment reserve.

We recommend that a process to replenish the reserve with international offsets purchased by a neutral 3rd party be added to the regulation. (SHELLENERGY)

> **Response**: We do not have the authority to use auction revenues in this manner. The activity may also make us a market participant, which could complicate our market operation and oversight role. We will have several mechanisms to monitor market performance to detect any issues that would result in unintended compliance costs.

D-56. Comment: Robust cost containment provisions are needed to address the potential for spiking ad runaway compliance costs.

Recommendation: Dow supports ARB's inclusion of a cost containment mechanism focused on allowance prices, with a ceiling price for accessing the Allowance Price Containment Reserve ("APCR") and a reserve price as part of the quarterly auction.

Rationale: Dow believes that including such a mechanism, if designed well, can reduce the volatility of allowance prices. Dow also supports ARB's proposed general usage restrictions, such as limiting the ability to purchase from the reserve to complying entities, and requiring these entities to immediately retire any allowances purchased from the allowance reserve to their compliance accounts. Dow supports ARB's design decision to increase the offset limit to account for the allowances removed from the market to fill the allowance reserve. Dow supports the removal of proposed restrictions in section 95913 (c)(1)(B) that would require entities to empty both their limited use holding accounts and general holding accounts before accessing the allowance reserve. (DOWCHEM1)

> **Response:** We made the changes to the regulation suggested in the comment.

D-57. Comment: As currently drafted, the Proposed Regulation also lacks sufficient, effective, and appropriate cost containment measures. The Allowance Reserve does not provide a true ceiling on allowance prices, and CARB should implement a hard price ceiling. (SCE1)

> **Response:** We have made clear that it will not impose a hard price ceiling, as this would prevent the market from sending a clear market price signal. The Reserve mechanism, together with the increase in the offset use limit, does provide some buffer against price increases.

D-58. Comment: IEP believes that a cap needs to be placed on the CPI escalator when determining the Reserve Tier Prices. Business certainty and investment will be undermined if the CPI remains uncapped over the 2012-2020 timeframe, particularly if the federal government's expansion of the money supply results in high inflation. IEP recommends to place a "not to exceed" five percent cap on the annual increases to the CPI factor in the methodology to determine the Reserve Tier Prices. (IEPA)

> **Response**: We do not believe that federal monetary policies require a modification of the tier prices. If federal monetary policies do result in "high inflation" as the comment suggests, they would affect the general price level. That is, while the tier prices would rise, so would the price of allowances and electricity. Failing to index the tier prices in the face of inflation would lead to premature depletion of the reserve at low real prices (i.e., adjusted for inflation).

D-59. Comment: The current structure for bidding on the allowance reserve will lead to increased risks and costs for compliance entities. As currently designed, the Allowance Reserve is inaccessible, punitive, and potentially ineffective. The Proposed Regulation creates three tiers for the Allowance Reserve, with three initial price levels of $40, $45, and $50. Assuming a modest 2 percent inflation rate, these prices could reach around $69, $77, and $86 in 2020. Given the potential impact on the State economy and on electricity customers, these prices are set too high.

To protect the integrity of the California cap and trade program and to serve as an example for regional or federal emissions trading programs, CARB must avoid burdening California consumers with excessive costs as a result of the Cap and Trade program. Pulling allowances for the Allowance Reserve from under the cap (and thereby reducing the supply of available allowances) does not provide true long-term cost containment and will do little to alleviate the cost burden on covered entities and their customers. (SCE1)

> **Response:** We disagree with the comment that the high Reserve prices will increase electricity rates. Utilities receive a direct allocation covering their exposure, which should provide them the resources they need to protect ratepayers. We also disagree with the assertion that funding the reserve reduces the supply of compliance instruments. The reserve is "funded" through an

increase in the amount of offsets covered entities are allowed to use, from four percent of their obligations to eight percent.

D-60. Comment: ARB's proposed rule includes several provisions designed to help contain costs. These provisions are important not only for California, but for broader efforts to design effective climate policies. Given the political headwinds faced by climate policy in the U.S., ARB can provide valuable leadership by demonstrating that climate policy incorporating appropriate designs and safeguards can achieve important environmental benefits without undue risk to the economy. Design of an effective California cap and trade program can also go a long way to eliminating emerging misconceptions about the value of market-based mechanisms to achieving these goals.

Along with three-year compliance periods, allowance banking and the use of allowance offsets, ARB's proposed rule includes an Allowance Reserve ("Reserve") which is designed to help moderate allowance prices. The Reserve works, in effect, by increasing the supply of allowances when allowance prices rise to the level at which they can be purchased from the reserve ("Reserve trigger prices"). Accounting for forecast inflation, Reserve trigger prices will rise to \$68, \$76, and \$85 per metric ton (MT) by 2020.

While the reserve is likely to mitigate the potential for high allowance prices, its proposed design raises several concerns. First, the reserve is stocked by increasing the cap's stringency by one percent in the first Compliance Period, four percent in the second Compliance Period, and seven percent in the third Compliance Period. These are significant increases in cap stringency, particularly in the third compliance period. While the limit on offset use has been relaxed so as to exactly equal the increased cap stringency, the proposed changes significantly increase reliance on offset markets. If offsets become a low-cost source of emission reductions, then the increased cap stringency may not raise costs appreciably. However, if offsets are either in short supply or are more costly than anticipated, then ARB's proposed changes could actually raise costs, particularly (although not exclusively) during periods when allowances are below Reserve trigger prices. A Reserve design that relies less upon increasing cap stringency would reduce the risk that the reserve raises, rather than contains, costs. (ANALYSISGRP)

Response: We agree that if there are not sufficient offsets available for covered entities to use the full eight percent limit, then the method we use to fund the reserve could be seen as tightening the cap when market prices are below the tier prices. However, the comment ignores other parts of the regulation design. The auction reserve price is designed to support consistent incentives for the investment in offset projects. We contend this feature will ensure that offset projects are viable. We will also propose additional offset protocols as part of a separate rulemaking to help increase offset supply.

D-61. (multiple comments)

Comment: Second, the proposed Reserve does not completely eliminate the risk that allowance prices rise to unacceptably high levels. If the Reserve is exhausted, then allowance prices could rise well above the trigger prices established by ARB. In fact, as the Reserve becomes depleted, uncertainty about the risk of Reserve exhaustion and subsequent high allowance prices could lead to speculation that accelerates Reserve exhaustion.

ARB has alternatives available to address these concerns, many of which have been mentioned in prior comments. First, ARB could design the Reserve to hold a (roughly) constant, but smaller, quantity of allowances. To maintain a "steady-state" quantity of allowances, the Reserve could be replenished with additional allowances as it becomes depleted. One approach to replenishing the Reserve is to use revenues from the sale of Reserve allowances to purchase emission offsets. Another alternative for replenishing the Reserve is to borrow allowances from post-2020 commitments periods. Both of these alternatives can maintain environmental integrity of the policy.

By replenishing the Reserve so that it contains a (roughly) constant quantity of allowances at all times, the Reserve does not need to be initially stocked to provide cost containment for all contingencies over the period 2012 to 2020. Thus, replenishment allows a smaller Reserve to be maintained, which reduces the quantity of allowances that is required to initially stock the Reserve. Compared to ARB's proposed Reserve, this approach provides two advantages. First, it provides a sufficient supply of allowances to address all market contingencies, and, second, it avoids the need to significantly increase the stringency of emission targets in order to stock the Reserve.

In addition to incorporating mechanisms that replenish the Reserve, ARB could also employ alternative approaches to initially stocking the Reserve. For example, ARB could initially fill the Reserve with a mix of allowances from under the cap and offsets. Allowances from under the cap could be used to initially stock a smaller Reserve than is proposed by ARB, and the Reserve could be gradually expanded through offset purchases. (ANALYSISGRP)

Comment: The Board should amend the price containment reserve to replenish the reserve with offsets, obtained from third-party approved entities, if it becomes oversubscribed so as to provide for higher-confidence cost containment and to avoid depleting future allowance pools. (CCC, MAZOWITA)

> **Response**: The Reserve is not intended to "completely eliminate the risk that allowance prices rise to unacceptably high levels" as the comment asserts. We have been clear that there is no "hard price cap" in the program. We rejected that approach as leading to interference with market price signals. We created the reserve to serve as a buffer against higher prices. The Board has directed staff to monitor depletion of the reserve and make recommendations for program revision as needed.

We did not accept the proposal for replenishment of the reserve with offsets for two reasons. First, we do not have the authority to use auction revenue to purchase offsets. Second, this would make us a market participant, complicating our role as operator of the market.

We cannot replenish the reserve with allowances without tightening the cap.

D-62. Comment: Calpine supports the proposed regulation's establishment of an initial Reserve Price of $10 per metric ton of CO_2e for 2012 vintage allowances and $11.58 for 2015 vintage allowances. See 17 C.C.R. section 95911(b)(6) (proposed). So long as the proposed regulation is revised to provide transitional relief for long-term contract generators that cannot pass-through allowance costs, as described in section A of these comments, Calpine believes that setting a strong Reserve Price will encourage covered entities both to undertake cost-effective emissions reductions within their own footprint and to support the development of real, additional emissions reductions through certified offsets projects. (CALPINE1, CALPINE2)

Response: We did not make any changes to address long-term contracts because it is up to the parties to the contracts to determine how to allocate carbon costs among themselves. ARB will not involve itself in third party contracts that were negotiated between private parties. We appreciate the support for the reserve tier prices.

D-63. (multiple comments)

Comment: We are pleased to see CARB propose a floor price of $10/tonne, escalating at 5 percent per year to reach $15/tonne by 2020. This is considerably higher than RGGI's floor price of less than $2/tonne. At these levels, the floor price will send a steady signal to the market to find innovative ways of decreasing carbon emissions. We are encouraged that CARB is proposing to auction 100 percent of allowances in the transportation fuels sector and will require the investor-owned electric utilities to sell 100 percent of their allowances into a consignment auction. This means over half of all allowances issued in the program will be auctioned from the start and will increase to roughly three-quarters of all allowances by 2020. (NRDC1)

Comment: Set a very high minimum price on carbon emissions' permits. In my view, California is prehistoric in its efforts to reduce all sorts of pollution, waste, and environmental stressors. Almost anywhere on the planet earth, you will find a better mass transit system than here, which reduces pollution, waste, and stress. By installing carbon limits that decline and carbon emissions' permit prices that have a very high minimum price, you have the opportunity to help your state remain the golden state. (COLBY)

Response: We will continue to evaluate the treatment of transportation fuels in the cap-and-trade program, including the effects of allowance distribution to different sectors within the transportation sector, and propose any necessary changes to the regulation before the start of the second compliance period in 2015. We note the importance of transparent price signals for fuel consumers in achieving reductions in this sector.

D-64. (multiple comments)
Comment: Section 95911(b)(6)(A) sets the Auction Reserve Price for auctions conducted during 2012 at $10 for allowances from the 2012 allowance budget year, and $11.58 for allowances from the 2015 allowance budget year. The proposed regulation also provides for a 5 percent plus consumer price index (CPI) annual increase in the Reserve Price (section 95911(b)(6)(B)). CARB states that the purposes of the annual increase is to "provide incentives for direct emissions reductions and the investments in offset credit projects," and that the "auction reserve prices would need to increase to reflect the increased marginal abatement cost and the inflation rate; otherwise, the reserve price would no longer support direct reductions and offset projects as intended." (ISOR, p. IX-71) NCPA does not believe that the increases are necessary to meet this objective, nor are they consistent with the purpose of a three-year compliance period.

NCPA recommends that section 95911(b)(6) be revised to strike the annual escalation of 5 percent. Aside from CPI, there should be no increase in the ongoing Auction Reserve Price. The annual increase adversely impacts the utility of the three-year compliance period as a cost-containment tool by guaranteeing that allowance prices in the later years will be 5 percent higher. Furthermore, increases are not necessary to meet the objectives articulated in the ISOR, and should not be included. (NCPA1)

Comment: The Utilities are comfortable with the need to adjust the auction reserve prices for inflation as measured by the CPI. However, we do not believe that there is justification for adding an additional 5 percent, and recommend modifying sections 95910 and 95911 as follows:

(d) Reserve Tiers.

(3) Increase in Release Prices. In calendar years subsequent to 2012, allowances from each tier shall be offered at prices equal to the offer price for each tier from the previous calendar year increased by ~~5 percent plus~~ the rate of inflation as measured by the Consumer Price Index for All Urban Consumers.

(b) Auction Reserve Price Schedule.

(6) Method for Setting the Auction Reserve Price

(B) For auctions conducted in calendar years after 2012 the Reserve Prices shall be the Auction Reserve Prices for the previous calendar year increased annually by ~~5 percent plus~~ the rate of inflation as measured by the Consumer Price Index for All Urban Consumers. (MID1)

Comment: The auction reserve price (section 95911(b)(6)) prescribes the auction reserve price set for 2012 as well as the five percent price increase plus the rate of inflation. This setting of allowance prices is inconsistent with the basic premise of the cap and trade system to reflect the pricing fluctuations inherent in a free market trading system so that GHG reductions can be obtained in an efficient, market- based process. To be consistent with this premise, CARB should set the initial price floor of the allowance and allow the market to dictate future allowance prices. (PRAXAIR)

Comment: Floor price escalation beyond inflation is not necessary. SMUD understands the desire, with a new market, to provide market certainty to those making determinations about whether to invest in a given reduction measure. We also understand that a floor price for allowances offered at auction is one way to ensure certainty, and that discounting of future payoffs implies a potential need for an escalation of that floor price beyond normal inflation. However, as markets mature, such investment signals will no longer be necessary in the market. The five percent escalator will in the proposed regulations will eventually result in excessive prices for allowances, in particular if carried beyond the 2020 timeframe. For a program with such strong complementary policies, the notion of forcing the floor price up to arbitrarily high levels seems punitive towards market participants who are trying to balance the high costs of complementary programs with the cap and trade costs. SMUD would recommend that ARB signal its intent to reflect maturing markets by tapering the 'above inflation' escalation off over time so that the escalation ends at no greater than the rate of inflation in the last year of the program. (SMUD1)

Comment: The price floor for allowances should not increase by 5 percent annually. The proposed regulation would impose a price floor of $10 that would increase annually by 5 percent plus inflation. The Initial Statement of Reasons ("ISOR") states that the intent of the 5 percent inflator mechanism is to reflect the expectation that marginal abatement costs will increase overtime as lower cost abatement measures are undertaken first. This mechanism is unnecessary because the declining nature of the cap will ensure California reaches its AB 32 goals in spite of marginal abatement cost increases. Failure to delete this mechanism could result in unnecessary rate impacts on California's customers. (PACIFICOR1)

Comment: Section 95911(b)(6)(B) (p. A-88) provides for the Auction Reserve Price to increase annually by five percent plus the rate of inflation as measured by the Consumer Price Index. The ISOR explains that this is to reflect the rate of increase in marginal abatement costs, which is assumed to be seven percent per year. However, it is not clear why the rate of increase in marginal abatement costs should be assumed to be seven percent. Lower-cost abatement measures are expected to be undertaken first. AB 32 measures may lead to the development of new abatement opportunities and increased implementation of low-cost abatement measures (such as energy efficiency) over time, renewable energy costs may decrease, and low-cost sector-based offsets may become available in later compliance periods. For these reasons, the rate of increase in marginal abatement costs may not be as high as seven percent per year. The ISOR notes that "the reserve price will rise more slowly than the expected marginal abatement cost so that the reserve price does not make the program unnecessarily more expensive." As changes in the marginal abatement cost are difficult to predict, ARB should avoid rapidly increasing the Auction Reserve Price and risking making the program unnecessarily more expensive. Instead, the Auction Reserve Price should increase by the rate of inflation only. (SCPPA1)

Comment: We have proposed other measures in the draft that will not contain costs but increase them. Automatic increases of 5 percent plus the urban consumer price index annually is unnecessary. (AGCOALITION)

Comment: Section 95913(d)(3) (p. A-96) repeats section 95911(b)(6)(B) (p. A-88) and provides for the prices of allowances in the Allowance Price Containment Reserve to increase by five percent plus inflation each year. The ISOR states that this is to take into account the assumed increase in marginal abatement costs and allowance prices over time. However, as discussed above in section IX.B, the rate of increase in marginal abatement costs is unpredictable. Without more justification for the assumed increase in marginal abatement costs, the five percent annual increase should be removed and reserve allowance prices should increase with inflation only. (SCPPA1)

> **Response**: We propose an inflator mechanism based on the expectation that marginal abatement costs and offset project costs will increase over time as lower cost-abatement measures are undertaken first, and due to inflation. Auction reserve prices would need to increase to reflect the increased marginal abatement cost and the inflation rate; otherwise, the reserve price would no longer support direct reductions and offset projects as intended. Our economic analysis assumed a rate of increase in marginal abatement costs of 7 percent, without factoring in inflation. We propose to increase the reserve price by 5 percent, plus inflation each year, so that the reserve price continues to support direct reductions and offset investment as those become more expensive. At the same time, the reserve price will rise more slowly than the expected marginal abatement cost so that the reserve price does not make the program unnecessarily more expensive.
>
> In addition, the consistent auction reserve price escalator provides certainty to offset project developers. Stakeholders have voiced concerns that uncertainty over future offset prices could reduce the supply of offsets. The reserve price reduces this uncertainty.

D-65. Comment: Set the Auction Reserve price at $1.86/allowance to be consistent with RGGI and afford easier linkage to that system over time while minimizing leakage concerns. Alternatively, set the Auction Reserve Price at $5/allowance to minimize the shock to the price of wholesale electric power in California. At a $5 floor price, a power plant with an 8000 MMBtu/kWh heat rate and gas at $4/MMBtu will still face an increase in the cost of producing wholesale electric power of 7.15 percent which is more than sufficient to send the market price signals CARB seeks for the electric sector. (IEPA)

> **Response**: We believe the carbon price imposed by RGGI does not send an adequate signal to the market to foster innovated technology and promote a change of consumer behavior.

D-66. Comment: The price floor of $10 a unit has been set too high. (INDENVASSOC)

> **Response:** We disagree that a floor price of $10 per metric ton is too high. We believe setting the reserve price at this dollar amount will ensure that allowance prices do not get too low to stimulate emissions reductions, and sends a signal to technology developers, as well as those investing in GHG offset projects.

D-67. Comment: The proposed methodology for setting an Auction Reserve Price includes an escalator of five percent per year plus the rate of inflation as measured by the Consumer Price Index ("CPI") for All Urban Consumers. A real risk exists that over the 2012-2020 timeframe, the CPI will escalate dramatically due to national expansions of the money supply to counter the ongoing recession. An unbounded CPI escalator factored into the methodology for setting the Auction Reserve Price creates a level of price risk that may undermine public support for the program goals that spur the types of investment needed to mitigate GHG emissions. IEP recommends bounding the CPI escalator component of the methodology to determine the Auction Reserve Price. (IEPA)

> **Response**: If an expansion of the money supply occurs and has the effect suggested by the comment, then it should raise the general price level. The price of allowances and offsets should increase along with the general price level. The auction reserve price should increase along with these in order to provide the same level of support for both direct reductions and offset projects.

D-68. Comment: Either a reserve price has no impact, or it artificially increases costs to society of the program. (MSCG2)

> **Response:** An auction reserve price set at the right level provides a known price floor to support investment in direct reductions and offset credit projects. We believe our auction reserve price could accommodate such goals. We will also create a market surveillance committee to closely monitor the market reaction.

D-69. (multiple comments)
Comment: CARB staff proposes a price containment mechanism with floor and ceiling prices to moderate allowance prices. The level of pricing in the allowance containment reserve is not well justified, more data is needed. The $10 floor may be far too high (particularly compared to prevailing carbon prices in other markets) and extremely damaging economic outcomes may be experienced at market prices much less than the proposed ceiling. The proposed levels are not well-justified in the regulation. (CMTA1)

Comment: The proposed floor price of $10/unit is not adequately justified. Setting the price floor at more than 5 times the known trading price in the US is not adequately justified and places California companies at an immediate competitive disadvantage. ARB should delay setting a floor price, and adopt a new floor price by regulation every three years that would better reflect the market conditions and trading partners. (SOLARTURBINES1, SDCHAMBER)

Comment: The $10 price floor for the auction of allowances is unrelated to any finding that it is necessary to spur market activity that would not also occur at $5, for example. (CALFP1)

> **Response**: The auction reserve price is one of the components of a linked regional market program for which consistency across the individual programs is especially important. For this reason, we will work closely to evaluate this issue with other WCI jurisdictions while evaluating their programs for possible linkage. We may propose an adjustment to the reserve price as part of changes made to link California's program with the programs established by WCI partner jurisdictions.
>
> We chose the $10 reserve price for two reasons. First, we are concerned that through recessionary economic conditions or forecasting error the cap-setting procedure may accidently lead to the creation of excess allowances. Throughout the regulatory process, we heard concerns from environmental groups that the cap would be unintentionally set too lax—a condition sometimes referred to as "oversupply" or "over-allocation." The over-allocation condition occurs if too many allowances are supplied to covered entities relative to expected business-as-usual emissions levels. If the cap is set too loose, prices will be lower than expected, and a weakened incentive to reduce emissions will be created. The reserve price mechanism would correct this condition by transferring excess allowances to future auctions. Second, staff is adapting the approach used in the federal Waxman-Markey proposal (HR 2454), which proposed a reserve price of $10 with an inflator mechanism of 5 percent per year plus inflation.
>
> Finally, ARB does not consider the prices observed in markets, such as RGGI, as representative of the marginal cost of abatement or production of offsets. These prices are instead the result of the over allocation problem that ARB is determined to prevent in California.

D-70. Comment: Section 95913(d) (p. A-95) provides that the allowances in the Allowance Price Containment Reserve will be divided into three tiers, each with a different price. The ISOR provides no justification for the tiering. There are a few sentences on this issue in the last paragraph of Appendix G to the ISOR: "If the first tier is exhausted quickly and purchases are made from the higher tiers, then a more significant imbalance is occurring..." However, it is not clear whether the use of tiers would provide significantly more information on supply-demand imbalances than would be provided simply by observing the percentage of allowances sold from a single-tier reserve at any point in time. Unless tiers can be shown to provide valuable information on imbalances that is not otherwise available, the tiers should be rejected as an unnecessary complication. (SCPPA1)

Response: We propose the three tiers so that in the event that covered entities purchase from the reserve, we could obtain information on entities' willingness to pay for allowances. This information would not be available if there were a single tier. In addition, we and several commenters acknowledge that once the top tier is accessed there is incentive for speculative purchases from the reserve. This could happen right away if there is only one tier.

D-71. (multiple comments)
Comment: Section 95913(d)(2) (p. A-96) sets out allowance prices for each tier of the Allowance Price Containment Reserve in 2012: $40, $45, and $50. The ISOR does not provide any detailed justification for setting the reserve prices at these levels. The reserve price should be set higher than expected allowance prices so that it does not interfere with price discovery, but lower than allowances prices in high-cost scenarios (ISOR Appendix G at G-19). As allowance prices are estimated to be approximately $15 in 2012 (according to Tables G-3 to G-5 in Appendix G of the ISOR), a reserve price that starts at $30, being double the expected 2012 allowance price. A reserve price that starts at $30 would start high enough to avoid interference with price discovery while being low enough to contain prices within tolerable levels. (SCPPA1)

Comment: The level of pricing in the allowance containment reserve is not well justified, as more data is needed. The CARB staff report finds that $30 is the estimated cost for abatement, yet the $40 level is the starting point for the high prices. (CALFP1)

Response: Staff did not propose a $30 price for the lowest tier in order to facilitate future linkage with the WCI. The $40 price for the lowest tier would be consistent with the level of the carbon tax set by the British Columbia Carbon Tax Act. When developing a single market like that being developed in the WCI, it is crucial to set up consistent price floors among future WCI partners and prevent leakage.

D-72. (multiple comments)
Comment: Thank you for including a permit price floor starting at $10/ton in the proposed Cap and Trade regulation. (SONOMAFCC)

Comment: I support a permit price floor starting at $10 per ton. (FRIEDENBERG)

Comment: We commend CARB staff for including a price floor of $10/ton into the proposed regulation. (CPC1, CPC2)

Comment: We believe that one of the program's strongest features is the $10 per allowance price floor, which escalates 5 percent plus inflation per year. This steady price signal will help businesses make long-term investments in strategies to reduce global warming pollution. (UCS1, LUDLOW, WALTERS)

Response: Thank you for the support.

D-73. Comment: If cap and trade is adopted, I would urge CARB to place some dollar value on every pollution allowance that is auctioned and to avoid any free allowances. If CARB is serious about attaining the rigorous goals of AB 32, which will be complicated by our burgeoning population, than it should ensure a reasonable price is placed on all carbon allowances from the outset. Sensitive to the current economic conditions in this state and country, I understand the possible desire to delay imposition of charging for all credits in order to minimize additional burdens to business in this state. While the goal is laudable, I think the better approach is to settle for some price that is reasonable, so as to set the proper price signal, and further propose a steady ratcheting up of the price, offset by a return of the revenues to the people of this state after a reasonable offset by CARB to pay for the cost of implementing AB 32. That way, an early signal is sent so that renewable energy gains a faster competitive edge which investors will consider to determine when and how much to invest in California's new, clean energy sectors. At the same time, a return of most of the revenues to the people of this state alleviates the impacts to the most affected people in a progressive manner. (REAVES)

> **Response**: The floor price for the auctioned allowances is 10 dollars and increases each subsequent year. We are auctioning a large number of allowances during the first compliance period, along with all of the allowances issued under the enlarged scope beginning with the second compliance period. However, at the beginning of the program we are providing some amount of free allowances to help covered entities transition into the program, but the amount of free allowances declines each year.

D-74. Comment: We support floor prices in auctions (though not in the market as a whole) and have suggested that the EU should also adopt such a policy. However, at $10 a ton, the level of the floor is currently too low to provide an adequate investment signal. We consider that this should be subject to regular review and increased as soon as possible. The use of revenues from auctions to mitigate price impacts on consumer costs is very sensible. Grants for deployment of low carbon technologies can also play a role in buying down the costs of higher cost abatement options but care should be taken not to unduly distort the abatement market by appearing to pick winners. The market would achieve this more efficiently than a government program, if changes can be made to introduce stronger ambition, long-term certainty and less offsetting. (SANDBAGCC)

> **Response**: The auction reserve price starts at $10, which is high enough to support the initial expected offset credits price. This price will continue to increase annually, which should provide an adequate price signal to encourage technology innovation. In addition, we will monitor the annual emissions level and compare that against the carbon price to see if the carbon price is at the right level to provide enough incentives for curbing carbon emissions.

D-75. Comment: The Reserve Tier Prices are set at a price four times (400 percent) the proposed initial Auction Reserve Price of $10/allowance. The purpose of establishing an Allowance Price Containment Reserve, theoretically, is to mitigate extreme volatility in the prices faced by obligated entities to acquire allowances. To achieve this outcome, the reserve price should be set high enough to allow market price signals to operate, but not so high as to be irrelevant to the goal of mitigating extreme price volatility and unintended impacts on key economic sectors such as electricity. Setting the Reserve Tier Prices at 400 percent of the initial Auction Reserve Price does not protect against extreme price volatility, particularly in the early years of AB 32 implementation. IEP recommends to set the Reserve Tier Price at 150 percent of the market-clearing price of the most recent auction capped at the proposed Reserve Tier Prices (i.e., Tier I: $40/allowance; Tier II: $45/allowance; and Tier III: $50/allowance). This approach will mitigate volatile price impacts while still creating the appropriate incentives for obligated entities to participate in the auctions (rather than seek allowances via the Reserve). (IEPA)

> **Response**: We disagree with the assertion that the reserve tier prices are too high. The Reserve is intended only to serve as a temporary buffer against extremely high prices to give staff time to make program revisions. It is not intended to keep prices in some range that stakeholders find reasonable.

D-76. Comment: The allowance price containment reserve should start at $30. The proposed regulation would prescribe allowance prices for the Allowance Reserve at $40, $45, and $50, with these prices to rise annually. PacifiCorp urges ARB to lower the reserve price, so that the reserve prices are lower than allowances prices in high-cost scenarios. Since allowance prices are estimated to be roughly $15 in 2012, the reserve price should be set high enough above that price to ensure that the reserve is not simply used as an alternative source of supply. Setting reserve prices to start at $30, $35, and $40 would strike a reasonable balance, as these prices would be high enough to avoid interference with price discovery and low enough to contain prices within reasonable levels. (PACIFICOR1)

> **Response**: Setting the reserve tier prices as suggested in the comment would interfere with operation of the market. This would eliminate a main purpose of the market, to signal the cost of carbon abatement. Again, we have always intended the reserve to serve as a last-ditch buffer against unexpectedly high prices. It is a temporary buffer intended to give us time to revise the program, not provide an absolute price guarantee.

D-77. Comment: CLFP recommends that CARB postpone determination of the reserve sale price thresholds until the regulation is more complete. The allocation benchmarks and all the monitoring tools established the ability to accurately measure leakage and anticipate other potential market failures. This will dictate the appropriate levels for the reserve pricing necessary to ensure market stability. (CALFP1)

Response: Before we set the reserve tier purchase prices we examined the results of our economic analysis to determine what were the most likely price outcomes. We set the reserve tier purchase prices above the prices from those analyses, so that the reserve tier prices would represent cases where our expectations about market outcomes were wrong. The reserve prices were not intended to "stabilize" market prices around some desirable level. Instead, they are designed to give us time to modify the program if it turns out that our understanding of the costs of meeting the cap were wrong. We believe that the reserve will buffer the program against higher prices and leakage long enough for staff to develop changes to the program. We conclude that we can go forward with the existing reserve prices, and change them later if needed.

D-78. Comment: The reserve price is set too high. CARB is proposing to sell allowances at $40 per metric ton beginning in 2012 rising to $75/metric ton in 2020. The escalating cost of the reserve over time negates the overall purpose of the reserve to serve as a cost-containment mechanism. We are concerned about the potentially high cost of allowances under this reserve system. We are also concerned that CARB has determined allowance prices before finalizing key elements of the program that could in fact influence the overall pricing outcome and will be useful in setting appropriate levels for the price reserve. Before setting price levels, CARB must first resolve important issues including benchmarking, allowances, leakage assessment, compliance and enforcement and monitoring tools. (CALCHAMBER1)

Response: We have completed the regulation and have not found any evidence that the reserve tier prices are not set correctly.

Setting the reserve tier prices lower, as suggested in the comment, would interfere with operation of the market. This would eliminate a main purpose of the market: to signal the cost of carbon abatement. Again, we have always intended the reserve to serve as a buffer against unexpectedly high prices. It is a temporary buffer intended to give staff time to revise the program, not provide an absolute price guarantee.

D-79. Comment: The proposed allowance reserve price is too high. Reserve prices similar to those used in the Northeast's Regional Greenhouse Gas Reduction Initiative (RGGI) should be applied, especially as linkage between the two would benefit both programs. The proposed $45 price containment reserve price is substantially above the current domestic and international markets. The RGGI market is currently trading at 1.85 per ton CO_2e. Given this magnitude of discrepancy, it is extremely difficult to budget power generation finances. (CONSTELLATIONENERGY)

Response: We disagree with the comment that the reserve price is set too high. See the response to Comments D-77 and D-78. Furthermore, the low prices in the RGGI market are due to chronic over-allocation, and they do not reflect a reliable estimate of the costs of abatement. The cap in RGGI did not decline in the initial years, as the cap in California will.

D-80. (multiple comments)
Comment: The Reserve Account (section 95870(a)), is a key tool toward mitigating potential adverse impacts on compliance entities due to the volatility of allowances prices. We recommend that the section 95913(d)(3) be revised to remove the annual 5 percent increase in the Reserve Account allowance prices. The annual increase, if any, should be no more than CPI, and there should be no other increase in the Reserve Price. Annual increases in the Reserve Account allowance prices adversely impacts two important cost containment tools—the Reserve Account itself, as well as the 3-year compliance period, by ensuing that the costs will be at least 5 percent higher each subsequent year. Furthermore, as with the Auction Reserve Price, annual increases in the price of allowances placed into the Reserve Account are not necessary to meet the objectives articulated in the ISOR, nor do they send additional positive market signals. Accordingly, they should be stricken. (NCPA1)

Comment: The allowance price containment reserve should not include tiers or annual adjustment beyond inflation. AB 32 workshop discussions have previously focused on an allowance reserve set using allowance prices in the range of $25 per ton to $30 per ton plus inflation only, without three separate tiers or a 5 percent annual adjustment. While the intent is to make the reserve the "last resort", extracting higher revenues from the sale of reserve allowances is not the correct policy focus and LADWP recommends that it be reconsidered. If the allowance reserve is tapped into at some point in the program, it should signal an "emergency" in the program and ARB should focus on the market factors contributing to the need to purchase allowances from the reserve. An allowance price of $50 per ton (plus 5 percent annually and inflation) for emissions will add significant costs to the price of electricity at a time when such pricing that may not be warranted or publicly supported. (LADWP1)

> **Response**: We selected a tiered structure for the reserve in order to have some warning about the increase in high prices. The Board has directed us to monitor the reserve and make recommendations for program revision. As prices rise and covered entities begin to access the reserve, we will have time to make such recommendations.
>
> Our economic analysis incorporated a rate of increase in marginal abatement costs of seven percent, without factoring in inflation. We propose to increase the reserve price by five percent, plus inflation each year, so that the reserve price continues to support direct reductions and offset investment as those become more expensive. At the same time, the reserve price will rise more slowly than the expected marginal abatement cost so that the reserve price does not make the program unnecessarily more expensive.
>
> Setting the reserve tier prices lower, as suggested in the comment, would clearly interfere with operation of the market. This would eliminate a main purpose of the market: to signal the cost of carbon abatement. Again, we have always intended the reserve to serve as a last-ditch buffer against unexpectedly high

prices. It is a temporary buffer intended to give use time to revise the program, not provide an absolute price guarantee.

D-81. Comment: PG&E supports the inclusion of the allowance price containment reserve in the Cap and Trade regulation and recommends that ARB monitor the potential for depletion of allowances. PG&E is concerned that the ability of the allowance reserve to mitigate allowance price volatility could be compromised by a shortage in the supply of offsets, faster than expected economic growth, reduced efficacy of the complementary measures, or unforeseen events such as a prolonged drought or an extended outage of one of California's nuclear units. To ensure that the allowance reserve remains adequate over time, PG&E recommends that ARB establish a formal review process that would include monitoring the allowance market for potential market failures or unsustainably high allowance prices, and develop a contingency plan that could be implemented should the allowance reserve approach low levels. PG&E supports:

- The inclusion of a cost containment mechanism focused on allowance prices, with a ceiling price for accessing the Allowance Price Containment Reserve and a reserve price as part of the quarterly auction.
- ARB's decision to establish an allowance reserve filled with allowances made available for sale at specified prices during direct quarterly sales.
- Their general usage restrictions, such as limiting the ability to purchase from the reserve to complying entities, and requiring these entities to immediately retire any allowances purchased from the allowance reserve to their compliance accounts.
- ARB's decision to increase the offset limit to account for the allowances removed from the market to fill the allowance reserve. (PGE1)

Response: The Board Resolution 10-42 instructed staff to monitor depletion of the reserve, determine the cause, and make recommendations for corrective actions. The resolution did not specifically include a contingency plan. Staff will be investigating a number of options in responding to this direction from the Board, including obtaining advice on how to monitor and modify the program with the help of a standing Market Surveillance Committee composed of academic experts.

D-82. (multiple comments)
Comment: PG&E recommends that ARB actively monitor the allowance market for the possible depletion of the reserve. PG&E recommends that ARB establish a contingency plan to address potential allowance price containment reserve depletion. PG&E recommends that ARB establish a plan that they would immediately implement in the event 50 percent of the allowances in the reserve have been purchased. PG&E's recommended plan is as follows:

- Use revenue from the sale of reserve allowances to refill the reserve with Reducing Emissions from Deforestation and Forest Degradation (REDD) offset credits; (PGE1)
- Make available additional and adequate supply to the market in a timely manner from an increase in the offset supply via an increased offset limit. To provide

adequate supply for this increased limit, ARB should adopt additional protocols and/or link to existing offset programs such as the Clean Development Mechanism (CDM), and linking with other cap and trade programs; (PGE1)

- In the event additional and adequate supply of compliance instruments is not immediately available, temporarily suspend the Cap and Trade program and the entities' associated compliance responsibility until additional and adequate supply becomes available; and (PGE1)
- If the above measures are not successful, ARB should adjust the overall allowance budget commensurate with higher than expected economic growth or electric demand, or lower-than-expected availability of offsets or lower-than-expected effectiveness of program measures. PG&E recommends the above corrective measures be taken to ensure an adequate quantity of compliance instruments is available and to avoid the potential for market failure. Additional supply may help to stabilize the cap and trade and related markets, such as the wholesale electric commodity market, and take pressure off the reserve. In the event adequate supply is not immediately available, suspension of the program and associated compliance responsibility will provide time for additional supply to be made available, and avoid price run-ups in wholesale electric commodity markets and other related markets. (PGE1)

Comment: There should be specifics on what market signals ARB will monitor in determining the amounts and timing of auctions/releases. (SOLARTURBINES1)

Comment: Accordingly, it's imperative that quarterly auctions and sales from the Allowance Price Containment Reserve Account (Reserve Account) are settled in a timely manner. The proposed regulation is also devoid of specific information regarding monitoring and tracking, which should be included. (NCPA1)

Comment: Program monitoring is incredibly important. We are encouraged by the provisions that were included in the resolution that provide for program monitoring. In particular, it's important to monitor the quantity of allowances in the reserve. The resolution directs staff to provide a report and recommendations to the Board when one of the tiers is depleted. We think ARB needs a more specific plan in place to take corrective action in a timely manner to protect the important cost containment feature of this reserve. (PGE2)

> **Response**: We believe it is important to have a comprehensive market-monitoring plan to detect fraud and prevent manipulation. We are working to create a market surveillance committee charged with such task. Monitoring, tracking, and any additional oversight are part of program implementation and are not included in this regulation.
>
> We agree that only covered entities should have access to the reserve. We disagree that the reserve should be refilled with any kind of offset credits, for two reasons. First, refilling the reserve will create a situation where all emissions reduction would come from offset projects. Second, refilling the reserve will

discourage covered entities from investing in energy improvements and technology innovation. Either scenario will incur an unfavorable result and tarnish the program's integrity.

The Board directed staff to monitor depletion of the reserve and develop recommendations to revise the cap-and-trade program if the reserve is depleted. While these recommendations could include changes to offsets use limits, changes to the cap, or other measures, the Board did not provide direction to include specific provisions, such as those recommended in the PGE comments.

Auction Requirements

D-83. (multiple comments)
Comment: Minimize unnecessary bureaucratic requirements

- Disclosure of unnecessary information will place significant unnecessary reporting burden (i.e. Time of transaction, time of settlement, price) [pg 107 (b)(3,4,5)]
- Reporting of transaction to ARB is unnecessary since it will be recorded on the registry [pg 108 (c')] (CCEEB1)

Response: Reporting transactions to the tracking system is how the market participants will report their transactions to ARB. We have revised the regulation to remove the requirement that the time of transactions is reported. We retained the requirement to report price because it is an essential element of market monitoring.

D-83.5 (multiple comments)
Comment: Finally, section 95913(c)(1)(B) provides that Covered Entities must have "no compliance instruments in their holding accounts or limited use holding accounts" in order to purchase allowances from the Reserve Account. The ISOR supports this limitation based on the notion that the Reserve Account be available to ensure "that compliance may be achieved at a reasonable cost." (ISOR, p. IX-87) We recommend that this limitation be revised to allow Covered Entities that hold offset instruments in their holding accounts to still purchase allowances from the Reserve Account due to the fact that the cost of offset projects can and should be distinguished. (NCPA1)

Comment: WPTF agrees with ARB's goal of ensuring that allowances purchased in the auction price reserve must be used for compliance. However, we believe that the requirement that covered entities must hold no compliance instruments in their holding accounts or limited use holding accounts is unnecessary and would limit the utility of the price reserve auction as a cost-containment mechanism. This requirement would require covered entities to 'pre-retire' all allowances, even those which have been purchased or banked for use in later years, to compliance accounts (or sell them off) to remove them from holding accounts. This outcome would greatly restrict the flexibility of covered entities to plan for compliance and respond to market conditions. Because allowances purchased from the reserve are placed directly into compliance accounts from which they cannot be further transferred, there is no need to additionally require that a covered entities' holding accounts are empty as a condition for participation in the auctions. Rules for access to the price reserve should not require entities to pre-retire all allowances. WPTF recommends that this requirement be removed from the regulation. (WPTF)

Comment: Covered entities should be allowed to purchase allowances from the allowance price containment reserve even if the entity has offset credits in its holding account. (OFFSETSWG1)

Comment: Modify section 95913(c)(1)(B) as follows:

> (B) Only covered entities (including opt-in covered entities) which hold no ~~compliance instruments~~ allowances in their holding accounts or limited use holding accounts may purchase allowances from the Allowance Price Containment Reserve. Covered entities may purchase allowances from the Allowance Price Containment Reserve regardless of whether they hold offset credits in their holding accounts or limited use holding accounts. (OFFSETSWG1)

Comment: The Utilities believe a covered entity should be allowed to hold offsets in their holding account and maintain access to the reserve. Modify section 95913 (Sale of Allowances from the Allowance Price Containment Reserve) as follows:

> *(c) Timing, Eligible participants, and Limitations.*
>
> *(1) Eligible participants*
>
> *(B) Only covered entities (including opt-in covered entities) which hold no allowances ~~compliance instruments~~ in their holding accounts or limited use holding accounts may purchase allowances from the Allowance Price Containment Reserve.* (MID1)

> **Response**: We agree with the comments, and the restrictions have been removed.

D-84. Comment: The proposed regulation should clarify CARB's position that Covered Entities are not subject to transaction fees for their purchases and sales in the auction, including all allowances that are consigned for auction from the Limited Use Holding Accounts. While the auction may be a revenue source for obtaining additional monies for implementation of the State's AB 32 programs, those revenues should not be raised from the mandatory participation of entities with a Compliance Obligations, but rather by third parties voluntarily participating in the auction. (NCPA1)

> **Response**: There are no transaction costs, registration fees, or consignment fees laid out in the regulation.

D-85. Comment: The Utilities are concerned that subsection 95912(e) lacks the necessary due process for allowing a bidder, after the Executive Officer has determined that they are in violation, to present information that may controvert or mitigate that determination. The Utilities suggest such a process be included in this section. (MID1)

Response: No provisions for due process were added to the regulation because ARB's process for investigating violations includes discussions with the entity where needed.

D-86. Comment: PG&E recommends that ARB include additional regulatory language detailing the design and implementation of the Cap and Trade auction to ensure efficient market functioning. The proposed regulation lacks sufficient detail concerning market systems, information systems and trading platforms for the primary auction market. ARB should provide additional details on the design and implementation of the proposed Cap and Trade auction. We recommend that ARB provide additional detail in the proposed regulation on auction design including the following: credit management process, default management process, definition of security and rating requirements, credit terms, revenue shortfall allocation, and settlements. In addition, we recommend that ARB address a number of questions, including: [NOTE: This comment refers to the following series of comments, through D-92.] (PGE1)

Response: The regulation sets out the rules that registered entities must follow, which in this case includes the bid guarantee and information submission for auction and reserve sale participation. Generally, administrative processes such as the ones listed are not included in the regulation beyond the specification of the rules themselves, and are considered part of program implementation.

D-87. Comment: a. Will ARB staff or a third party contractor administer the auctions? This issue needs to be resolved promptly to allow sufficient time to address credit requirements, default provisions, and other auction design details. (PGE1)

Response: This is part of program implementation and is also being addressed as part of WCI linkage. Regardless of the entity administering the program, the first auction is not until mid-2012. We believe there is sufficient time to resolve the questions raised by the commenter.

D-88. Comment: What specific credit, collateral and security requirements will be imposed on all parties in the quarterly auctions? (PGE1)

Response: The regulations will impose only the credit, collateral, and security requirements contained in section 95912(h).

D-89. Comment: c. How will ARB manage the credit process for each auction? How will ARB handle defaults? How will ARB perform settlements? (PGE1)

Response: The rules governing these processes are set out in sections 95912(h), 95912(k)(2), and 95912(k)(3), respectively. The exact communications needed to complete these processes are part of program operation, not the regulation, and will be published by the Executive Officer and the financial services administrator well in advance of any auction or Reserve sales.

D-90. Comment: What is the potential for market abuse or manipulation e.g. “cornering” or “squeezing,” in the quarterly auctions at the end of a three-year compliance period, when the allowance needs of covered entities are more defined? (PGE1)

Response: We consider the period around the triennial compliance deadlines as one of heightened risk of market manipulation. We have proposed several rule provisions to deal with the potential problem. Section 95921(e) prohibits specific trading practices that could be used to manipulate the market. The holding limit contained in section 95920 is designed to prevent an entity from holding sufficient allowances to be in a position to execute a “squeeze.” The purchase limit in section 95911(c) is intended to prevent an entity from concentrating its purchases at the end of a compliance period. Without this provision, an entity could potentially deprive covered entities of allowances while building up a supply of allowances to sell. A purchase limit could force speculative entities attempting to build a substantial position to spread their purchases over several auctions. This provides notice to covered entities that they must bid more competitively to secure the allowances they need in order to reduce the need to purchase on the secondary market. Finally, the regulation provides for the publication by ARB of market and auction data that will both protect the identity of those trading and provide market participants with data on price trends. This transparency will help covered entities understand the potential for market manipulation at any time.

D-91. Comment: PG&E recommends that ARB modify the proposed rule to address these and other critical auction design issues. This will ensure that the systems and resources are in place to support a fully tested and workable market. In addition, PG&E believes it is important to review how the primary auction market will interact with secondary bilateral markets. (PGE1)

Response: Many of these issues are part of program implementation and do not require regulatory text modifications. We will be closely monitoring the primary and secondary markets, along with any interactions between the two. We will be contracting with an independent market-monitoring service, as well as creating a Market Surveillance Committee of academic experts, to ensure ongoing evaluation of the efficiency of our market rules.

D-92. Comment: PG&E requests additional clarification on text related to auction design. Section 95814(a)(2)(A) would allow registration as a voluntarily associated entity to an entity that intends to purchase, hold, sell or voluntarily retire compliance instruments. However, section 95802(a)(207) defines a voluntarily associated entity more narrowly, as an entity that intends to voluntarily retire compliance instruments.

PG&E understands that ARB's intent is to use the definition in section 95814(a)(2)(A) and will correct the definition in section 95802 (a)(207) . (PGE1)

> **Response**: We agree with the comment and revised the definition of voluntarily associated entity in section 95802(a).

D-93. (multiple comments)
Comment: CARB staff proposes that free allowances in the first compliance period be followed by auctions in the second and third, with specific recommendations on percentage allowance allocations based on assigned leakage risks. An auction scheme for allowances will impose very high costs on regulated parties, which will, in turn, be passed through to the economy as a whole. Unless and until California has transitioned to a comprehensive national program with similar costs imposed on competitor states and nations an auction will fail and do untold harm to the State's economy. The regulation should be clear that auctions are not authorized until carbon trading reaches sufficient scale to reap its anticipated benefits and not decimate the state economy. When California is part of a broad national program with similar allowance allocation requirements, we can consider if an auction is appropriate and cost effective, but until that occurs, CIPA supports only free allowance distribution for all sectors for each compliance period up to 2020. (PLOTKIN)

Comment: An auction scheme for allowances will impose very high costs on the public agencies and companies subject to the program. For this and other reasons we have vigorously opposed any immediate auction for the first compliance period, and we have the same objection about later compliance periods if California has not by then transitioned to a comprehensive national program with similar costs imposed on competitor states and nations. Therefore, unless and until California is part of a broad national program with similar allowance allocation requirements, we support only free allowance distribution for all sectors for each compliance period up to 2020. (AB 32IG)

Comment: The proposed price floor is problematic without a corresponding price ceiling. The proposed regulation provides only a price floor known as the Auction Reserve Price, reasoning that the Allowance Reserve would provide a measure of cost containment and act as a price ceiling. This reasoning is faulty since allowances can be purchased over the Allowance Reserve prices. Though a rational market participant would not purchase allowances above the reserve price if allowances are available in the reserve, it is not clear that supply in the Allowance Reserve will be sufficient to meet market demand. Therefore, allowances may be sold and purchased at higher prices in quarterly auctions and secondary markets if and when the Allowance Reserve is depleted. A hard cap on GHG allowance prices would be a more effective cost containment measure. Absent such a cap and under the proposed structure, CARB cannot ensure that the legislature's concerns regarding cost containment will be addressed. (SCE1)

> **Response**: We do not consider the Allowance Price Containment Reserve to be a price ceiling. We rejected the idea of a hard price ceiling as inconsistent with a

market-based measure. We agree with the comment in that the reserve reduces upward pressures until it is exhausted, but staff also contends the effectiveness of the reserve diminishes once market participants believe it will be exhausted. We did not intend the reserve to completely eliminate price increases. Rather, the reserve provides some cost containment as the reserve was "funded" through an increase in the quantitative use limit for offsets from four percent to eight percent. We acknowledge that the reserve could be exhausted; a condition that we understand would require revision to the cap-and-trade program. The nature of these revisions would be subject to public comment and a Board consideration.

D-94. Comment: California learned the importance of a hard price ceiling from the energy markets during the California energy crisis. When buyers could benefit from higher prices, many engaged in aggressive bidding strategies, which resulted in extreme prices without actual supply shortages in the energy markets. These unreasonably high bids effectively withheld reasonably-priced supply from the markets. In that market, however, the incentive to push up prices was somewhat limited by the existence of hard price caps. Absent such price caps, California's energy crisis would have been far more severe, and economic disaster would have come much sooner. When FERC ultimately replaced these hard price caps with soft caps (similar to the even weaker price controls in CARB's cap and trade market design), it resulted in greater withholding of power, leading to shortages in the form of rolling blackouts. These shortages occurred even though the supply of power was more than adequate; it was simply withheld from the market. (SCE1)

Response: The electricity schemes described in the comment relied on the inability of the market to access reasonably priced generation due to congestion or due to withholding by the generators' operators. Since those two conditions occurred, price caps had some impact. In the carbon market, manipulators would have to find a similar way to prevent purchasers from accessing supplies of compliance instruments. The only way to do this would be to control a sufficient amount of instruments so that covered entities would have no choice but to purchase from them. These "pivotal" suppliers could then extract a higher price from covered entities that had not covered their emissions obligations.

ARB designed its holding limit to reduce the chance that any group of market participants could become pivotal suppliers. The holding limit in 2013 would limit a single entity to holding no more than about four percent of the allowances issued that year. ARB expects that this level would prevent an entity from becoming a pivotal supplier. Covered entities have a limited exemption from the limit to allow them to cover their emissions obligations. However, this exemption applies only to the allowances they place in their compliance accounts. Allowances cannot be removed from the compliance account, so these entities could not use their stockpiles of accumulated allowances to profit from a tight market. Once the covered entities cover their emissions obligations, they face the same holding limit as non-covered entities.

We believe that the holding limits will reduce the opportunity for the types of manipulation suggested in the comment. In addition, price caps are generally set very high in order to avoid distorting the price signal provided by the market. Thus, it would allow the exercise of market power until the manipulated price reaches the cap. Finally, the Allowance Price Containment Reserve is available to place a soft limit on price increases.

D-95. Comment: While allowance markets are not as vulnerable as electricity markets (since allowances can be stored more easily than electricity), the possibility for rampant abuses still remains due to the financial connection between GHG markets and electricity markets. If prices do reach intolerably high levels, then at least one of two preventable catastrophic outcomes will occur. First, the California economy could suffer undue economic harm, which is an unacceptable outcome. Second, excessive prices could undermine the very purpose of AB 32. A California-only program cannot adequately mitigate the climate change impacts of increased global GHG concentrations. What it can do is set an example of how to effectively and efficiently mitigate GHG at reasonable economic and social costs. If prices are allowed to reach excessively high levels, California's GHG regulation will be viewed as a failure and a deterrent to future GHG regulation. It has been over a decade since California's failed electricity market structure halted restructuring markets nationally, if not internationally. As discussed above, no U.S. state has restructured since that time. CARB's cap and trade design cannot allow such failure to occur. If a hard cap is not put in place, such failure may still be possible. (SCE1)

Response: We decided not to rely on hard price caps to prevent the manipulation of market prices for two reasons. First, price caps do not limit the exercise of market power until the caps are reached. Since a hard price cap could distort market price signals, the caps are generally set well above the range of expected prices. Second, the Allowance Price Containment Reserve provides a "soft" price ceiling. As long as the reserve contains sufficient allowances, it will dampen price increases below the tier prices. The Board has instructed staff to monitor depletion of the reserve and recommend corrective actions, including possible revision of the cap-and-trade program.

D-96. Comment: If no specific hard price cap is implemented, CARB must incorporate provisions in this cap and trade regulation allowing CARB to halt any quarterly auction to avoid excessively-priced GHG allowances that could cause irreversible harm to both the economy and the success of the GHG reduction program. (SCE1)

Response: We disagree with the comment. The presence of fixed-price tiers in the Allowance Price Containment Reserve will limit prices at the auction. The program will have a market monitor and market surveillance committee to identify any potential problems and recommend the specific actions the board should consider in response.

Allowance Reserve

D-97. Comment: Provide a discount for purchases of GHG allowances from the "allowance price containment reserve," which could extend to all sources identified in the "high risk" for leakage category. (SMITHS)

> **Response:** We disagree with this comment. We believe the direct allocations to covered entities are sufficient to address the leakage issue.

D-98. Comment: The proposed method of containing costs in the program is insufficient and will actually increase the prices of allowances. By moving 4 percent of allowances to the reserve at higher set prices, it will limit the supply to all and therefore increasing prices. Staff proposes to increase the offset allowances by 4 percent to 8 percent to compensate for the 4 percent being removed from the auction. It is our belief and one that we have shared at a workshop that the number of offsets available would not be expected to reach 4 percent of the allowances and therefore 8 percent would definitely not be available. So by trying to contain costs the program will remove a real 4 percent from the supply and compensate it with a 4 percent that is unlikely to be achieved because of the protocol standards. Real cost containment would be placing a cap on the price of emissions or increasing the total supply when high prices are reached. (AGCOALITION)

> **Response:** We disagree with the comment. We have expressed the concern that if market prices are too low then not enough offsets will be produced. However, the reserve only comes into play once market prices reach $40, and it continues to provide cost containment until the $50 tier is exhausted. At these market prices, we believe there will be enough offsets so that the quantitative use limit for offsets is a binding constraint. ARB estimates that there will be sufficient offset supply for the four offset protocols to meet offset needs for the first compliance period. We will also consider additional offset protocols to provide additional supply.

D-99. Comment: The ARB's proposed rule includes several provisions designed to help contain costs. These provisions are important not only for California, but for broader efforts to design effective climate policies. Given the political headwinds faced by climate policy in the U.S., ARB can provide valuable leadership by demonstrating that climate policy incorporating appropriate designs and safeguards can achieve important environmental benefits without undue risk to the economy. Design of an effective California cap and trade program can also go a long way to eliminating emerging misconceptions about the value of market-based mechanisms to achieving these goals. (ANALYSISGRP)

> **Response:** No response is needed.

D-100. Comment: Along with three-year compliance periods, allowance banking and the use of allowance offsets, ARB's proposed rule includes an Allowance Reserve

(“Reserve”) which is designed to help moderate allowance prices. The Reserve works, in effect, by increasing the supply of allowances when allowance prices rise to the level at which they can be purchased from the reserve (“Reserve trigger prices”). Accounting for forecast inflation, Reserve trigger prices will rise to $68, $76, and $85 per metric ton (MT) by 2020.

While the Reserve is likely to mitigate the potential for high allowance prices, its proposed design raises several concerns. First, the Reserve is stocked by increasing the cap’s stringency by 1 percent in the first Compliance Period, 4 percent in the second Compliance Period, and 7 percent in the third Compliance Period. These are significant increases in cap stringency, particularly in the third compliance period. While the limit on offset use has been relaxed so as to exactly equal the increased cap stringency, the proposed changes significantly increase reliance on offset markets. If offsets become a low-cost source of emission reductions, then the increased cap stringency may not raise costs appreciably. However, if offsets are either in short supply or are more costly than anticipated, then ARB’s proposed changes could actually raise costs, particularly (although not exclusively) during periods when allowances are below Reserve trigger prices. A Reserve design that relies less upon increasing cap stringency would reduce the risk that the Reserve raises, rather than contains, costs. (ANALYSISGRP)

> **Response**: We agree that the reserve will mitigate the potential for high allowance prices. However, we disagree with the comment that creating the reserve increases cap stringency, since we allow more offsets to be used for compliance approximately equal to the size of the reserve. If offsets take time to appear, or if they are more expensive than expected, then the means of funding the reserve could increase costs, but only slightly. Most of the reserve is funded through future vintage allowances. Only one percent of current vintage allowances are diverted to the reserve, but the offset use limit for the first compliance period is raised to eight percent. There would have to be a significant shortfall of offsets in the first period for the reserve to tighten the market. Even if a shortfall in offsets occurs and prices do rise, the reserve will not contribute to higher prices once the market price is high enough to cover offset project costs.

D-101. Comment: Second, the proposed Reserve does not completely eliminate the risk that allowance prices rise to unacceptably high levels. If the Reserve is exhausted, then allowance prices could rise well above the trigger prices established by ARB. In fact, as the Reserve becomes depleted, uncertainty about the risk of Reserve exhaustion and subsequent high allowance prices could lead to speculation that accelerates Reserve exhaustion. (ANALYSISGRP)

> **Response**: We agree with the comment, and the Board has directed staff to closely monitor depletion of the reserve. However, we have been clear that the reserve is not intended to serve as a hard price cap. Rather, the reserve serves to temporarily buffer unexpectedly high market prices until potential corrective actions can be taken.

D-102. (multiple comments)
Comment: ARB has alternatives available to address these concerns, many of which have been mentioned in prior comments. First, ARB could design the Reserve to hold a (roughly) constant, but smaller, quantity of allowances. To maintain a "steady-state" quantity of allowances, the Reserve could be replenished with additional allowances as it becomes depleted. One approach to replenishing the Reserve is to use revenues from the sale of Reserve allowances to purchase emission offsets. Another alternative for replenishing the Reserve is to borrow allowances from post-2020 commitments periods. Both of these alternatives can maintain environmental integrity of the policy.

By replenishing the Reserve so that it contains a (roughly) constant quantity of allowances at all times, the Reserve does not need to be initially stocked to provide cost containment for all contingencies over the period 2012 to 2020. Thus, replenishment allows a smaller Reserve to be maintained, which reduces the quantity of allowances that is required to initially stock the Reserve. Compared to ARB's proposed Reserve, this approach provides two advantages. First, it provides a sufficient supply of allowances to address all market contingencies, and, second, it avoids the need to significantly increase the stringency of emission targets in order to stock the Reserve. (ANALYSISGRP)

Comment: In addition to incorporating mechanisms that replenish the Reserve, ARB could also employ alternative approaches to initially stocking the Reserve. For example, ARB could initially fill the Reserve with a mix of allowances from under the cap and offsets. Allowances from under the cap could be used to initially stock a smaller Reserve than is proposed by ARB, and the Reserve could be gradually expanded through offset purchases. (ANALYSISGRP)

Comment: The proposed regulation will exacerbate price volatility, both by discouraging banking and by encouraging any firms that have maintained banks to sell those allowances en masse when prices are high in order to gain access to the reserve. (While such a sell-off might help bring prices down, it will do so in a much less controlled and much more volatile fashion than if banking were encouraged in the first place). EDF therefore recommends against requiring zero allowances in holding accounts before accessing the allowance reserve. (EDF1)

> **Response**: The Reserve is not intended to "completely eliminate the risk that allowance prices rise to unacceptably high levels" as the comment asserts. We have been clear that there is no "hard price cap" in the program. We rejected that approach as leading to interference with market price signals. We created the reserve to serve as a buffer against higher prices. The Board has directed staff to monitor depletion of the reserve and make recommendations for program revision as needed.
>
> We did not accept the proposal for replenishment of the reserve with offsets for two reasons. First, we do not have the authority to use auction revenue to

purchase offsets. Second, this would make us a market participant, complicating our role as operator of the market.

We cannot replenish the reserve with allowances without tightening the cap.

D-103. Comment: As a further precaution against regulated entities effectively using the reserve to build up allowance banks, the regulation could deny access to the reserve to a regulated entity within 90 days of selling an allowance. (EDF1)

First, reserve allowances should be valid only for the compliance period in which they are issued. Second regulated entities should be denied access to the reserve in any compliance period in which they increase the number of allowances in their holding accounts (i.e., add to their allowance bank). This approach will not only prevent a regulated entity from buying reserve allowances and banking them, but also from buying reserve allowances and effectively substituting them for regular allowances which it could then bank. (EDF1)

Response: We disagree with the comment. Denying access to the reserve because of a recent sale by an entity could prevent the entity from responding to changing market conditions. We also disagree with the notion that entities will sell into the market above the tier prices, then buy from the tiers. It is not clear why the purchaser in the secondary market transaction wouldn't simply wait for a reserve sale. Finally, since the reserve is funded mostly with future vintage allowances, we cannot prevent the use of the reserve allowances for current compliance and still maintain cost containment.

D-104. Comment: LADWP strongly supports policies that have been incorporated into the proposed regulation intended to help contain compliance costs, including an allowance reserve. (LADWP1)

Response: No response needed.

D-105. Comment: The prices of the allowance reserve tiers should be more closely tied to actual market allowance prices. If properly designed, the allowance reserve can play an important role in containing costs in the cap and trade system. However, the price of allowances in the various reserve tiers is far too high, especially given CARB's estimate of allowances prices of $10 in 2012 and $20 in 2020. (BP)

Response: We agree that the reserve tier prices are above the prices staff expects to prevail in the market through 2020. However, the purpose of the reserve is to reduce price increases outside of the expected range of prices and not to dampen the price signal that is a main objective of the cap-and-trade program. The Reserve is intended to serve as both a last resort source of allowances and as an indicator that the cap-and-trade system has not potentially functioned as intended. We chose a fixed-price purchase format as opposed to a reserve auction in order to ensure the reserve allowances would be available at a known price. Behind this approach is the assumption that a drawdown of the reserve would be an indication that we may have underestimated the cost of cap-and-trade.

Miscellaneous

D-106. Comment: We agree with CARB's proposal to auction allowances required for the carbon content of transportation fuels delivered to end-users when they are brought into the cap in 2015. (ICCT1, ICCT2)

Response: No response is needed.

D-107. Comment: Section 95912(d)(1)(A) (p. A-91) prohibits entities from publicly releasing their "qualification status." This term is not defined. In order to avoid inadvertent breaches of this requirement due to entities not being aware of what information not to release, "qualification status" should be defined in the Cap and Trade Regulation. (SCPPA1)

Response: The text is in a section that discusses the requirements for participation in the auction, which includes approval by the Executive Officer of an auction registration application pursuant to section 95912. In this context the meaning of the term is clear.

D-108. Comment: SCE suggests that CARB seek out an independent, professional evaluation of its auction design to limit the potential for what could be drastic, unforeseen consequences. (SCE1)

Response: We have received comments from academic experts who have provided staff with numerous suggestions for improvements, such as more frequent auctions and double-sided auctions in which participants can bid to buy or sell. We are considering these options for future modifications.

E. COMPLIANCE OBLIGATION/COMPLIANCE CYCLE

This section includes comments and responses about applicability of the regulation (sections 95810–95814 of the regulation), details about compliance instruments (i.e., allowances and offset credits; sections 95820 and 95821), and compliance requirements for covered entities (sections 95850–95856). Major sub-topics include point of regulation, surrender and retirement of compliance instruments, compliance periods, recordkeeping and reporting, the treatment of municipal solid waste, and waste-water. We also discuss compliance obligations related to military facilities in this section.

Applicability

E-1. Comment: Anrafi Associates recommends that CARB revise its proposal of imposing charges for omissions or requiring offset use, to apply such appropriate provisions only to those designated major greenhouse gas business emitters who have not installed reasonable available control technology on their existing operations or best available control technology on their new operations. In other words, no charges for emissions or requirements for offset use should be imposed on businesses that are implementing cost effective reasonable and best CARB-controlled technologies. The advantage of this approach is that it would not penalize such designated businesses with added cost burdens if they have timely installed the appropriate technologies established by CARB. (ANRAFIASSOC)

> **Response:** We are implementing the cap-and-trade regulation to impose an economy-wide limit on GHG emissions, which no other regulation currently does. The requirement to use best available control technologies would not ensure that the 2020 GHG emissions level required by AB 32 is met. Under the regulation, a covered facility must surrender compliance instruments to cover its on-site emissions. If a facility has advanced control technology, it may benefit by reducing its compliance obligation or by receiving free allocations if it is an industrial facility eligible for industry assistance.

E-2. Comment: No provisions in the Draft Final Rule are made for existing facilities who are new program participants due to recent emission increases that occurred since 2009. With operating changes in 2010, Dow Pittsburg will be reporting for emissions to the ARB in 2011 for the first time and will be a new participant in the cap and trade program. ARB should provide definition and clarification for existing facilities that are now subject to the proposed program. (DOWCHEM1, DOWCHEM2, DOWCHEM3)

> **Response:** We will notify facilities that are required to report under the Mandatory Reporting Regulation (MRR) before the reporting deadline. Subsequently, the emissions that facilities report will be used to determine whether the cap-and-trade program covers that entity, and whether that entity has a compliance obligation. Section 95812 now includes mandatory reporting

data in 2011 as part of the information used to determine a facility's inclusion in cap-and-trade.

Military

E-3. (multiple comments)
Comment: Given the unique nature of the military mission, the potential disruption of military operations, the fiscal law restraints on federal agency purchases of Compliance Instruments, the limited availability of offsets, and the failure to analyze the impact on federal funding, DoD requests that the proposed regulations be modified to add the following exception:

New Section 95815. Military Facilities:
Military facilities that qualify as a "covered entity" pursuant to Section 95811 and that generate greater than 25,000 $MTCO_2e$ per year are exempt from this regulation until such time as the U.S. Congress authorizes federal expenditures to participate in a state greenhouse gas cap and trade program. (USDOD1)

Comment: In case of conflict or national security operations, DoD installations may experience rapid changes in activity levels, including increased energy and fuel use. These changes in activity level would be beyond the control of the individual installations or groups and may be sustained for significant periods of time. We would like to discuss options for special consideration for these periods, including linking surge with DoD's ability to reach back before 31 December, 2006, for military-generated offsets, as discussed above. Another option is providing a temporary exemption for these surge periods from compliance with the cap and trade program. Our goal is to avoid a situation where the cap and trade mandates conflict with mission requirements. (USDOD1)

Comment: Federal government must comply with acquisition requirements. The FAR provides an expansive set of controls governing the federal government's purchase of goods and service in the open market. There are mandates on ensuring open and fair competition. These regulations may limit the federal government's ability to participate in the auction to purchase Compliance Instruments. Since this is the primary mechanism to comply with a mandatory GHG emissions cap, federal agencies may be significantly disadvantaged in their compliance efforts. In the absence of specific Congressional authorization federal agencies may be barred from participating in the program outside of the FAR mandates. The timing and likelihood of Congressional approval is currently unknown. (USDOD1)

Comment: Supreme Court Justice Steven Breyer has noted, "The concerns that led to the development of this case law, such as fears of unjustified raids on the federal treasury by states or attempts by states to discourage federal activity within their borders, would seem applicable in the present context." Maine v. Navy, 973 F.2d 1007, (1st Cir. 1992)(Breyer, C.J.)(citing McCulloch v. Maryland, 17 U.S. (4 Wheat.) 316, 426-27, 4 L.Ed. 579 (1819); Public Util. Comm'n v. United States, 355 U.S. 534, 543-44, 78

S.Ct. 446, 452-53, 2 L.Ed.2d 470 (1958). The DoD applauds the portions of the proposed C&T rulemaking that require the use of revenues generated by the program to be used in ways similar in purpose to the program's goals. However, we would be remiss if we did not take note of anecdotes of similar programs where funds have been spent in ways inconsistent with the general welfare of the federal taxpayer.

For example, "In just over two years, the (Regional Greenhouse Gas Initiative (RGGI)) has generated more than $729 million for the 10 states that have participated. Each state is supposed to use its share of the money raised to invest in renewable energy and to promote energy efficiency and consumer benefits, like programs that help low-income electricity customers pay their utility bills. But the money is proving too much of a temptation for states not to use [as] a convenient pool of money that can be drawn on to help balance state budgets. Critics say that diverting money from the fund for general spending, instead of using it on emissions control and energy savings, makes the initiative little more than a hidden tax on electricity." Mireya Navvaro, States Diverting Money From Climate Initiative, N.Y. Times, November 28, 2010 (USDOD1)

Comment: The DoD concerns reflect the discussions around AB 1405 (2010), which would have earmarked a substantial portion of cap and trade revenues to fund a wide range of social-based programs provided by non-governmental organizations (NGOs). Although Governor Schwarzenegger vetoed this bill, a public discussion of the ARB 2010 Legislative Report revealed that both NGOs and ARB Board members thought that despite the fate of the legislation, ARB had the authority and willingness to implement these social programs. While these publicly funded NGO programs may not be a part of the current proposal, DoD must view this proposal through that history. If revenues from the auction of Compliance Instrument are earmarked for these social programs, then federal agencies may be barred on constitutional grounds from participating in a primary method of compliance. (USDOD1, USDOD2)

Comment: There is yet another fiscal law issue in that to the extent the military is put in a position of selling instruments on the open market, and receives a surplus from the sale of that trading allowance, the military may be illegally augmenting its federal budget. The DoD may not accept allowances from the ARB as that term is defined in the proposed regulation due to the augmentation rule. "The (augmentation) rule is that a government agency may not accept for its own use (i.e., for retention by the agency or credit to its own appropriations) gifts of money or other property in the absence of specific statutory authority. 16 Comp. Gen. 911 (1937)." U.S. Government Accountability Office, Office of General Counsel, Principles of Federal Appropriations Law, (The Red Book) 3d ed., Vol. II, p. 6-222. "As the Comptroller General (has) said, '[w]hen the Congress has considered desirable the receipt of donations...it has generally made specific provision therefore ....' Id. at 6-223 (citing 16 Comp. Gen. 911, 912; See also B-286182, Jan. 11, 2001; B-289903, Mar. 4, 2002 (nondecision letter)). Thus, acceptance of a gift of money or other property by an agency lacking statutory authority to do so is an improper augmentation.

The following discussion from the Comptroller General summarizes the illegal augmentation theory:

Although there is no express statutory prohibition against augmentation of appropriated funds, the theory, propounded by the accounting officers of the Government since the earliest days of our Nation, is designed to implement the Constitutional prerogative of the Congress to exercise the power of the purse; that is, to restrict executive spending to the amounts appropriated by the Congress. See e.g. 9 COMP.DEC. 174(1902).

Several implementing statutes further assure that agencies do not accept additional monies from sources other than the Congress itself. For example,18 U.S.C. 209 prohibits acceptance of any salary payment or other compensation for a Government employee from any source outside the Government. Funds may not even be transferred between separate Government appropriations without specific statutory authority. 31 U.S.C. 1532. Contributions or donations from outside sources are made to Government agencies, in the absence of statutory authority to retain them, they must be deposited promptly in the general fund of the Treasury. 31 U.S.C. 3302. Violations of any of the above statutes constitute an illegal "augmentation of the agency's appropriation and the funds must be disgorged and returned to the Treasury so that they can be appropriated as the Congress sees fit.

Matter of: FCC Acceptance of Rent Free Space and Services at Expositions and Trade Shows, June 28, 1984, B-210620, 63 COMP.GEN. 459.

Determining whether C&T revenues make the program subject to the illegal augmentation rule requires consideration of several factors. Among those factors include the purpose of the appropriation, the amount of discretion in the uses of the funds and the nature of the augmentation itself, whether cash or value in-kind.

Applying those factors to the proposed C&T rulemaking, ARB Staff Report: ISOR PROPOSED REGULATION TO IMPLEMENT THE CALIFORNIA CAP- AND-TRADE PROGRAM, Volume II, Appendix D, states: "The value of the allowances is represented by the money paid to the State, which would then have the opportunity to use the revenue for public benefit."(D-20) "Allowance value can be used in many ways, including use for the public benefit or to ease the cost of regulation."(D-22) "Regulating greenhouse gas emissions will probably stimulate economic growth in some sectors and may slow growth in others. Worker training programs funded with allowance value can help Californians shift jobs if necessary."(D-22) The allowances were clearly designed in consideration of both economic value to the position holder and accomplishment of the regulatory goal, GHG reduction. The economics of the program distinguish C&T from a traditional air pollution control or abatement program. Considered in tandem with the legislative histories of AB 1405, Proposition 26 and the 3 parts of the Massachusetts test outlined above, the problems of DoD participation are evident. (USDOD1, USDOD2)

Comment: California Government Code section11346.5(6) requires the notice of proposed adoption to include "an estimate [of] the cost or savings to any state agency, [other] nondiscretionary costs imposed on local agencies, and the cost or savings in federal funding to the state." The term 'federal funding' is interpreted broadly and it includes the addition or subtraction of federal programs within the state. According to California Government Code section 11349.1, "The (Office of Administrative Law) shall return any regulation (where) the adopting agency has not prepared the estimate required by (section 11346.5(6)) and has not included the data used and calculations made and the summary report of the estimate in the file of the rulemaking." (For rules governing the preparation of this statement, see California Code sections13000 et seq. (Department of Finance)). There is no analysis in the Initial Statement of Reasons on the economic impact of this regulation upon the agencies of the federal government. Absent this analysis, OAL must return this regulation to ARB under state law. (USDOD1)

Comment: We have had meaningful discussion regarding the unique, world-wide reach of California's DoD installations, as well as the breadth of the services provided to the service members on base, analogous to municipal jurisdictions. Consistent with this viewpoint, ARB discussed an exception for military base operations in the preamble to the California mandatory GHG reporting regulation:

> “Another exception to the traditional facility definition is military bases. Some military bases are spread over many thousands of acres and encompass a wide variety of activities such as employee housing, medical facilities, airfield operations, aircraft repair, ship construction and repair, and other operations. Each of these operations could also be under the operational control of different branches of the military or military contractors within the confines of a base. ARB staff has thus provided the option for a military base to subdivide the base for reporting purposes into independent functional groupings, based on the types of operations performed on the bases. Through this mechanism, each base would not necessarily have to report as a single facility, but could subdivide based on “operational control"' (defined in the regulation), and on major functional groupings such as aircraft repair and overhaul or ship construction and repair operations. As with traditional "facilities," only those GHG sources specified within the proposed regulation would be reported, while unspecified sources such as residential heating and cooling would not be included.”

Based on this rationale, ARB's mandatory reporting regulation definition of "facility" states that operators of military installations may classify such installations as more than a single facility based on distinct and independent functional groupings within contiguous military properties. We would therefore request consistent treatment of DoD's military installations in the California cap and trade regulation. This avoids a scenario where a single power plant on a city-sized military installation results in the entire operations of the installation being subject to cap and trade requirements. We do not believe such an outcome would be consistent with how municipalities are being treated under ARB's final GHG reporting rule and under the preliminary draft cap and trade rule, and as such may be outside of the federal waiver of sovereign immunity. (USDOD1)

Comment: We are concerned that routine movement of fuel from a ship to shore, or from shore to ship or one of our island facilities could trigger cap and trade requirements. Our interpretation of this preliminary draft regulation is that the proper application is when fuel is purchased within California from a supplier who would be subject to compliance. Other movement of fuels, as part of the military mission function, should not be subject to regulation that could impact our mission needs and flexibility. Therefore, we would ask that fuel movements on behalf of the United States military or for military purposes be exempted from these requirements. (USDOD1)

Comment: The inclusion of a major new sector of Fuel Suppliers in 2015 requires additional analysis that we have not completed. It goes without saying that the ability to supply fuel to our major installations in CA, much of which is transported and combusted outside of CA, is an instrumental part of DoD's world-wide operational mission. We ask that you work with us to ensure that this aspect of our mission is not covered by this regulation. (USDOD1, USDOD2)

Comment: Other specialized fuels, which are moved on behalf of the United States military or for military purposes, are not part of the transportation sector. We request that the regulation provide a exemption to avoid ambiguity. We note that addressing the DoD fuel movements in this manner would be consistent with the EPA's Mandatory Greenhouse Gas Reporting Rule (MRR) in Title 40 of the Code of Federal Regulations Part 98 at section 98.6. (USDOD1)

Comment: The treatment of transportation fuels raises an issue for DoD in California. While the current proposal onIy includes gasoline and diesel, placeholders exist for other transportation fuels. At least one DoD installation has a production facility creating biodiesel fuel from waste cooking oil and others are being considered. DoD would like to know if/how such production would be treated. DoD would not believe it appropriate to '"penalize"' a facility that produces biofuel from non-foodstocks. (USDOD1)

Comment: We wish to express our support for the three-year compliance periods to enhance compliance options and flexibility with this very new program. Facilities will need to develop complex compliance strategies to comply with this regulation and the three-year window in which to implement the strategy will provide facilities the flexibility needed to do so while still meeting national security demands. As pointed out earlier, DoD's mission requirements can quickly change in response to world events. It is imperative that we retain the maximum flexibility for compliance. (USDOD1)

Comment: A significant means to comply with mandatory GHG emissions is to participate in the "trading" portion of the C&T program, and to obtain Compliance Instruments at auction or in the anticipated market. These innovative and precedential compliance mandates raise issues not previously addressed. An initial analysis, based on the information provided to date, indicates that federal fiscal law constraints may prohibit federal agencies from obtaining the Instruments in those ways. (USDOD1, USDOD2)

Comment: The Supremacy Clause of the U.S. Constitution also prohibits states taxing the federal government. Further, the federal agencies can only pay a state "fee," if the charge is in accord with well-established U.S. Supreme Court precedent (see U.S. v Massachusetts, 435 US 444 (1978)), and U.S. Government Accountability Office (GAO) opinions. Federal agency acquisition of goods and services must also comply with the Federal Acquisition Regulation (FAR). The application of these authorities to the purchase of Compliance Instruments in the GHG cap and trade program presents a number of concerns. DoD will require additional time to review the proposed program, especially since the ARB staff report states that additional modifications are anticipated. (USDOD1)

Comment: State revenues generated must approximate costs of the GHG program. The ARB Staff Report discusses that Compliance Instrument auctions may result in revenues to the state and that revenues may be expended by providing rebates to electricity rate payers or by investing in the "green" economy to stimulate research and jobs. If revenues in excess of program costs are generated, federal agencies may be barred by federal law from participation in the purchase of Compliance Instruments at auction. (USDOD1)

Comment: Federal government must receive benefits commensurate with the amounts paid. The revenue generated in an auction also may be reinvested for the "public benefit." The benefits to the public at large are usually paid for by taxes, and the State cannot tax the federal government. If the distribution of the amounts paid by federal agencies for Compliance Instruments does not result in commensurate benefits, then they may be barred from participation in the auctions. (USDOD1)

Comment: The Cap and Trade Program will initially apply to one facility in the Marine Corps at 29 Palms. If the draft program were implemented, the facility might have to choose to reduce its electricity generation in order to avoid compliance obligation. And that puts us in the path of the legal problem my colleague mentioned about not being able to purchase allocations. Based on these concerns as well as those stated by the DoD representative, we hope that you recognize the unique role of the federal military and support our request for an exemption from the program. (MCIW)

Comment: Many of the DoD's energy reduction initiatives emanating from the federal requirements referenced above will meet the formal "offsets" criteria and will be an important part of the DoD compliance strategy. Consider, for example, the Navy installation of San Clemente Island, which is not on the power grid; therefore, all power generated comes from liquid fossil fuels barged from the mainland. There is no other way to access "green power." In recognition of the impacts from this energy transfer. the Navy implemented an alternative energy project on San Clemente Island in 1998 comprising 675 KW of wind power, which supplies up to 15 percent of the island's power. We have asked for recognition of these efforts throughout the AB 32 implementation process and continue to do so today. Given the variability of the DoD mission and changing national security needs, we are particularly concerned about requirements for offsets should a "surge" occur due to training/mission needs. For this reason, we seek to ensure recognition of our past efforts. (USDOD1)

Comment: DoD has facilities through the country and the world and must manage these in a constantly changing environment. For this reason, we request that CA 's cap and trade offsets include the widest geographic coverage. For example, if we seek to bring a new mission to California that would increase a cap we would want to have the opportunity to use reductions from elsewhere, e.g. the facility where the mission is coming from or other offset projects. (USDOD1)

Comment: Currently the offset market is narrowly limited to the four following protocols: 1. Urban Forest Projects, 2. Ozone Depleting Substances Projects, 3. Livestock Manure (Digester) Projects, and 4. U.S. Forest Projects. The military is concerned that its inability to purchase Compliance Instruments requires us to generate our own offsets to comply with this regulation. As explained above, the federal government has for years taken actions to reduce its energy use and GHG footprint. These reductions are regularly monitored with executive level oversight at CEQ and OMB, both agencies independent of DoD, charged with implementing these initiatives. To the extent that the military is subject to the Cap-and- trade program, we recommend that the Executive Officer, in his authority within Sub article 13, Sections 95970-95973, approve federally mandated protocols for offsets. These federal reductions will meet regulatory criteria for offsets outlined in Section 95972 for protocols, i.e., accurate accounting, data collection and monitoring, project baseline, and ensuring the reductions are permanent. The proposed capture of offsets is overly restrictive in this current draft, and should be expanded to recognize federal reduction offset protocols. (USDOD1)

Comment: In accordance with ARB's approved "Policy Statement on Voluntary Early Actions to Reduce Greenhouse Gas Emissions," we recommend that ARB consider moving the date for Offset Project Eligibility (page 64 of the PDR) from 31 December, 2006 back in time, to allow for recognition of significant projects such as the Navy's 1998 installation of wind turbines on San Clemente Island. As we understand ARB's rationale for the 31 December 2006 cut off, it corresponds to the date of implementation of AB 32. DoD installations in California have implemented many high quality projects that could be considered as offset credits in the California Cap and Trade market. Setting a date at 3I December 1997 will allow some of these projects to be eligible for offset credit generation and will reward the early actors in accordance with ARB's policy. An earlier offset project eligibility date is more in line with the legislatively mandated baseline year of 1990 and will allow consideration of renewable energy projects which take many years to implement. (USDOD1)

Comment: As we have discussed in our comments on the mandatory reporting rule, DoD is subject to unique requirements that pose issues for verification through third parties. We appreciate the inclusion of local air districts in the verification and support continued utilization of local air districts in the verification process of offsets. (USDOD1)

> **Response:** After further consideration of military concerns, we agreed to exempt military facilities from this regulation for one year while other regulatory options are further explored. The military exemption was part of the second 15-day changes to the regulation. We will coordinate with the military to better understand their written concerns and implications for national security. Any alternative direct regulations will be designed to ensure the military also reduces its GHGs as other facilities are required to do under the cap-and-trade program.
>
> In addition, Board Resolution 11-32 directed the Executive Officer to partner with the air quality management districts and air pollution control districts in the implementation of the cap-and-trade regulation, including, but not limited to, an evaluation of the impacts of the cap-and-trade program on industrial source greenhouse gas permitting and implementation of the Adaptive Management Plan. The Board further directed the Executive Officer to report back periodically to the Board on the nature and extent of this partnership, with the first report due in the first quarter of calendar year 2012.

CO_2 Suppliers

E-4. (multiple comments)
Comment: Only CO_2 producers, not CO_2 suppliers, should be covered entities. At its carbon dioxide plants, Praxair obtains certain refinery gas streams rich in CO_2 and purifies them into carbon dioxide which can be used in many processes like food freezing and beer carbonation. Praxair does not produce the carbon dioxide it processes. If Praxair did not take and purify the refinery gas streams, they would be emitted at the refinery as a waste gas.

Section 95811(g) provides that suppliers of carbon dioxide are covered entities. A "supplier" is defined in section 95802 as "a producer, importer, or exporter of a fossil fuel or an industrial greenhouse gas." As a result of this proposed definition it appears that CARB would subject a number of entities along the supply chain to a compliance obligation, including not only Praxair as a purifier and distributor of CO_2 to its customers (but not as a producer of CO_2) but also its customers. Carbon dioxide producers alone, as the generators of the raw CO_2, should bear sole responsibility for CO_2 controls, and not those entities recycling and distributing the CO_2. Subjecting multiple entities in the same supply chain is simply unfair and economically onerous on CO_2 recyclers, distributors, and their customers. Imposition of additional compliance obligations for distribution-related activities may threaten Praxair's continued CO_2 supplier operations within the state. Carbon dioxide suppliers do not create the raw CO_2 that they purify and render into usable products for consumer and commercial use the producers do; therefore, producers should solely bear the costs of such production and subsequent users of the raw CO_2 should be exempted from this Proposed Rule.

CARB has acknowledged that raw/waste gas CO_2 purchased, purified, and sold by CO_2 suppliers is produced primarily by petroleum refineries. Application of compliance obligations solely on the producers of this CO_2 is entirely consistent with CARB's identification of other covered entities in section 95811, e.g., lime manufacturers, cement manufacturers, petroleum refineries, iron and steel mills, and many others that produce CO_2 as waste emissions from their manufacturing operations. Moreover, imposition of compliance obligations on CO_2 suppliers is inconsistent with the U.S. Environmental Protection Agency's (EPA) comprehensive regulatory scheme requiring both the mandatory reporting of GHG emissions and, separately, controls of such GHG emissions. EPA's rules fairly and appropriately provide that the producers or manufacturers of raw/waste gas CO_2 bear the sole responsibility and liability for monitoring and controlling such CO_2 emissions. Even CARB's Mandatory Reporting Regulation is consistent with the federal reporting scheme, providing that only suppliers of carbon dioxide that are included in 40 CFR Sec. 98.2 are required to report under the Mandatory Reporting Rule (section 95101(a)(1)(B)).

Imposition of these proposed compliance obligations will encourage substantial leakage as well, encouraging out-of-state CO_2 suppliers to import into California just enough quantities of CO_2 to fall below the 25,000 metric ton/year threshold and avoid the burdensome costs imposed on in-state suppliers to acquire allowances, potentially undercutting in-state businesses such as Praxair's. CARB staff recognized, in our recent meeting, the distinction between production and the suppliers' role in distribution, and conceptually agreed that only one entity in the supply chain should be subject to the compliance obligation. Praxair looks forward to continuing discussions with Staff to improve the Proposed Rule in this regard.

However, should CARB determine not to exempt such CO_2 suppliers, then CARB should allocate free allowances to such suppliers in recognition of leakage risk and to avoid substantial adverse economic harm to CO_2 suppliers. Moreover, such industry assistance might enhance innovative use of CO_2 for positive environmental and sustainability purposes (e.g., use of CO_2 as a refrigerant versus environmental damaging alternatives such as ammonia, ozone depleting substances, or other chemicals with higher GHG warming potentials and longer atmospheric persistence). (PRAXAIR)

Comment: CARB should not impose a compliance obligation on CO_2 suppliers unless there are net imports greater than 25,000 metric tons of CO_2e annually. Section 95852(g) provides that "[A]n entity that supplies carbon dioxide covered under section 95811(g) has an aggregated compliance obligation based on the sum of imported and exported quantities of CO_2."

Praxair transports CO_2 product in and out of California, mostly by CO_2 trailers and railcars as a normal course of business. This movement across state borders allows for the most efficient utilization of our capital and resources, enabling lower costs to supply and lower prices to customers. For example, it may be more efficient and cost-effective to import CO_2 from Oregon to supply northern California customers while exporting CO_2 from southern California to supply Arizona customers.

As written, the proposed regulation would penalize a company for making these types of cross border shipments by requiring the purchase of allowances for both the imports and the exports. This would have the unintended impact of increasing CO_2 trailer delivery miles to avoid cross-border movement, resulting in higher costs to Praxair and other CO_2 suppliers as well as higher overall carbon footprint due to incremental transportation activities.

Praxair has two CO_2 production plants in California. At both of these plants, the raw/waste gas CO_2 purchased is produced as an off-gas by a neighboring petroleum refinery and sold to Praxair for recycling and purification prior to resale of the CO_2 to wholesale and retail customers. These producers have compliance obligations for this CO_2 as covered entities. If Praxair exports the CO_2 outside of California, however, Praxair would then have a compliance obligation because this material is being exported. The effect of this export is a double counting of the CO_2 molecules and thus a double compliance obligation—the first obligation falling on the producer and the second obligation falling on the supplier. Imposing such additional costs is arbitrary and unreasonable.

This also places Praxair at a competitive economic disadvantage, with respect to product CO_2 being produced in California, with CO_2 that is sourced from other states' markets, resulting in leakage.

Another real life example of leakage that can occur if exports are required to have allowances is as follows. A few years ago Praxair was involved with a promising CO_2 reduction project in which CO_2 recycled from a refinery was shipped out-of-state to a customer that previously generated their own CO_2 from an on-site lime kiln operation. By changing from CO_2 production to purchase of recycled and purified refinery off-gas, this project resulted in a "net" CO_2 emissions reduction. If under the Proposed Rule this exported CO_2 would now be subject to a compliance burden, there is a strong likelihood that the economics of this transaction will erode, and the customer will revert to producing their own CO_2.

We encourage CARB to provide in the final regulation that exported CO_2 that has already been subject to regulatory coverage as produced CO_2 (e.g., petroleum refining as a CO_2 producer) should be excluded from a CO_2 supplier's determination of its aggregated compliance obligation. This approach is consistent with the concept that only one entity in the chain of custody should be subject to the compliance obligation. Should a supplier's net imports exceed the threshold for reporting—and the CO_2 was not already subject to an upstream compliance obligation—only then should such a supplier be subject to a compliance obligation for such imported CO_2. (PRAXAIR)

Response: We modified the compliance obligation for CO_2 suppliers to include only in-state production or extraction of CO_2 for supply to commercial applications or for geological sequestration. The threshold remains 25,000 metric tons CO_2 per year. We modified the regulation to exclude exported CO_2 from a CO_2 supplier's compliance obligation unless it is being exported for use in geologic sequestration, as we do not want to incentivize out-of-state geologic sequestration without rigorous assurance that the CO_2 will remain permanently stored underground. We further modified the regulation to exclude CO_2 imports from a compliance obligation, as we assume that imports are relatively small, and those imports would need free allocations to ensure similar treatment as in-state production of supplied CO_2. Instead of providing free allocation of allowances for a relatively small amount of CO_2, we chose to monitor imports; if CO_2 imports increase, ARB will reassess its treatment of imported CO_2.

Fuels

E-5. Comment: We believe that the treatment of fuels under the cap in 2015 will place an unreasonable burden on producers and/or consumers of those fuels in California. We encourage CARB to reconsider placing fuels under the Cap as they are already covered by a host of other regulations (Federal RFSII, LCFS, Pavely, etc). (TESORO)

Response: The cap-and-trade regulation establishes a declining limit (cap) on 85 percent of statewide GHG emissions, including fuels. The declining cap established in the regulation ensures that all necessary reductions occur to meet the 2020 target. We believe an economy-wide cap with a broad market is the best way to help meet that target.

E-6. Comment: ATA supports ARB's decision to maintain a phase-in approach for the incorporation of transportation fuels during the second compliance period in 2015 as opposed to requiring compliance for all sources beginning in 2012. The phase-in approach allows for the smoother implementation of a complex regulation, while also allowing additional time for harmonization with regulations in other jurisdictions, especially given the interstate nature of transportation fuel consumption and associated emissions. (ATAA)

Response: No response necessary.

E-7. Comment: The BMW Group supports the implementation of a Cap and Trade system for transportation fuels in order to reflect the growing use and availability of alternative fuels such as biofuels, electricity, and hydrogen. (BMWGROUP)

Comment: We support the inclusion of the carbon content of transportation fuels within cap and trade as a complimentary measure to vehicle standards, the LCFS, and policies to reduce vehicle miles traveled. (ICCT1)

Response: We appreciate the support.

E-8. Comment: Do not aggregate oil and natural gas systems' GHG emissions for defining a regulated source. The proposed regulations tie the definition of an oil and natural gas system compliance entity to CARE GHG reporting requirements which aggregate small oil and gas production emission sources at the basin level oil and natural gas system (section 95802(a)(138)). Oil and natural gas operations at a company are seldom organized at a basin level. Aggregating the reporting obligations at a basin level for oil and natural gas operations poses particular issues that are being discussed in the context of EPA's reporting rule. They raise similar and more relevant issues for the purpose of compliance. Historically, EPA has relied on a different definition of a facility that does not include the concept of aggregation at basin level for the purpose of compliance pursuant to the Clean Air Act. We believe that the inclusion of a basin level concept creates an artificial organizational layer that does not typically have a parallel in the organization structure of an oil and gas company. This would make it difficult to implement and demonstrate compliance obligations associated with the proposed regulations. In fact the reporting rule does state that the definition of a facility (that includes the concept of a basin) is for the purpose of that rule only. We agree and do not believe that it is logical to expand the definition of a facility beyond the reporting rule.

CARB should limit the definition of an oil and natural gas system compliance entity to single point sources emitting greater than 25,000 TCO_2e per year. (CONOCO)

> **Response:** Under the MRR and cap-and-trade regulation, oil and gas systems are reported and covered in a manner that is modeled after the U.S. Environmental Protection Agency (EPA) rule. We have tried to remain consistent in our reporting requirements in order to harmonize with the Federal Rule. We believe it is appropriate to require reporting at a basin level for this sector to include these sources of emissions under the cap if at that level of reporting the emissions exceed 25,000 metric tons of CO_2e.

E-9. Comment: The cap and trade program should not be extended to transportation consumer emissions as provisions of other federal and State programs address these. Additionally, fuel providers should not be responsible for these emissions that are directly consumer related. Transportation emissions should be considered only if a formal review determines that this action is necessary and implementation would be more cost-effective than other policy approaches. The proposed regulations include GHG emissions from consumer use of transportation fuels under the State emission cap starting in 2015 (section 95812(d)(1)). This results in a clear overlay to the existing federal Renewable Fuels Standard, the California Low Carbon Fuel Standard (LCFS), and State/federal vehicle GHG performance standards. Inclusion of transportation fuel emissions within the cap and trade program will add a volatile carbon cost to the price consumers already pay for GHG control measures such as LCFS and vehicle efficiency standards. In addition, fuels under the cap will increase administrative complexity and the market price of emission allowances for all the other capped sectors. Specifically, a carbon cost of $20 per ton would add a fuel cost burden in excess of $3 billion per year to the California economy. In addition to individual consumers, much of this cost will fall to businesses and municipalities impacting small business owners, truck drivers, city bus and trash services, construction companies, rail services, and others. This carbon cost, along with the cost of compliance for LCFS and federal programs, will be embedded into the costs of all goods and services that rely on transportation. CARB should not extend the cap and trade program to consumer emissions from use of transportation fuels. Instead, CARB should allow existing federal/state programs to address GHG emissions in this sector. This is consistent with the approach adopted in the European Union. Any inclusion of consumer use of transportation fuels under the state emission cap in 2015 should be contingent on a formal review and a conclusion that such a measure is necessary and cost-effective for achieving the State's GHG reduction goals. We seek the Board's resolution that would require staff to review inclusion of transportation consumer emissions in the cap. This review should be completed well before the proposed 2015 start date. (CONOCO)

Response: We believe that cap-and-trade’s market-based approach is the most cost-effective and practical approach to lower emissions throughout most of California’s economy. There are numerous sectors that are covered by direct regulation and the cap-and-trade regulation. For example, the electricity sector is subject to the Renewable Portfolio Standard as well as the cap-and-trade regulation. We believe that the cap-and-trade-program is complementary to existing renewable and LCFS standards and to other State or federal laws.

The LCFS regulates fuel producers by requiring them to reduce the carbon intensity of their fuels 10 percent by 2020. This is accomplished by creating various “fuel pathways” for fuels based on their lifecycle emissions, accounting for feedstocks, production processes, transporting fuels, and other factors. While the LCFS will incentivize the use of lower carbon, non-petroleum fuels, it does not address emissions from petroleum refineries. The cap-and-trade program addresses both facility emissions that occur from fuel production (beginning in the first compliance period) and accounts for combustion emissions from the fuel that is produced and sold in California (beginning in the second compliance period).

Placing a price signal on transportation fuels will reduce the consumption of transportation fuel; driving investment in newer, more fuel-efficient vehicles. Any GHG reductions resulting from federal regulations or the LCFS at covered entities would be counted as emission reductions under the cap-and-trade program.

We agree that cap-and-trade is not well-suited to address emissions from millions of distributed point sources such as automobiles. However, our approach is not to apply cap-and-trade to the end user (vehicle drivers), but to the fuel suppliers, who will be responsible for fuel that is combusted. By taking this “upstream” approach in the regulation, we avoid the challenges of applying it to millions of “downstream” users.

E-10. Comment: CARB's projected baseline emissions inventories do not appear to account for the expected shift from petroleum transportation fuels to biofuels in the future. This shift would set back CARB's efforts to achieve 2020 GHG goals unless transportation biofuels are included in cap and trade or the overall level of the cap and trade is reduced to account for leakage due to expected increasing levels of transportation biofuels. We strongly recommend that emissions from all transportation liquid fuels be treated equally and fuel providers should be held accountable under the cap for the carbon emissions of all biofuels. (KUSTIN03)

> **Response:** The cap-and-trade regulation will help transition California away from carbon-intensive fossil fuels to cleaner and more-efficient fuels. The fossil fuel portions of biofuels and bioenergy are under the cap. Transportation fuels and fuel suppliers will have a compliance obligation. However, biomass-derived fuels are exempt from a compliance obligation since CO_2 emissions resulting from the combustion of biomass are considered biogenic. Emissions from biomass-derived fuels must be reported and verified pursuant to the MRR. Source categories that are not listed under section 95852.2 (Emissions without a Compliance Obligation) or that have not received a qualified positive or positive verification statement must be reported as "other biomass CO_2." Other biomass emissions that cannot be verified pursuant to the MRR are not considered biomass-derived, and will hold a compliance obligation.

Natural Gas

E-11. Comment: The proposed regulation should be modified with respect to treatment of natural gas local distribution companies (LDC) to reflect that natural gas LDCs are already at the 1990 greenhouse gas emissions levels that AB 32 requires. The natural gas sector has already achieved the AB 32 target of being below 1990 greenhouse gas (GHG) emissions levels. The proposed regulation offers no credit for energy efficiency measures implemented over the past two decades that have led to significant and sustainable emissions reductions in the natural gas sector. The proposed regulation improperly includes natural gas LDCs under the Cap and Trade Program for the actions of end users that they do not control.

Accordingly, this sector has already carried out its responsibilities under AB 32. The sector is continuing to pursue programmatic measures through the CPUC that are anticipated to achieve further reductions to maintain GHG emissions at 1990 levels even with economic growth. It serves no purpose to subject the small natural gas customers to the added costs of the Cap and Trade Program when it has already done its share by incurring costs already for energy efficiency measures over the past two decades as well as implementing an inverted rate structure that provides incentives for conservation and energy efficiency. (SEMPRA1)

> **Response:** We believe that returning to the 1990 GHG emission level is a statewide goal that does not apply to each individual industry or facility level. To

achieve the mandates of AB 32, it will be essential for continued reductions in all sectors.

E-12. Comment: We consider inclusion of the commercial and residential natural gas customers an unproductive action by ARB. Including these customers with no allocation of allowance value seems entirely at odds with AB 32's direction that ARB "Ensure that entities that have voluntarily reduced their greenhouse gas emissions prior to the implementation of this section receive appropriate credit for early voluntary reductions." (SEMPRA1)

> **Response:** We disagree. The carbon price signal created by the coverage of natural gas used by commercial and residential customers will create an incentive for conservation of this fuel. Reduced natural gas usage will lead to reduced greenhouse gas emissions.

E-13. Comment: Natural Gas Liquids used as feedstocks for petrochemicals are non-emissive and should be exempt from regulation. Compliance obligations for odorized propane should be delayed until 2015 to match the phase in date for local distribution companies (LDC) and transportation fuels, since propane competes directly with natural gas in these markets. (WSPA1)

> **Response:** While the program covers suppliers of liquefied natural gas (LNG), which is derived by fractionating natural gas liquid, it does not cover suppliers of natural gas liquid. The emissions associated with producing natural gas liquid may be covered if a facility exceeds the applicability threshold. Therefore, natural gas liquids used as feedstock are not covered. Section 95851(b) states that suppliers of LNG will have a compliance obligation starting 2015.

E-14. Comment: Only odorized propane needs to have an allowance obligation and the entity with title to the propane at the point of odorization should be responsible. The Propane Education and Research Council (PERC) fee currently applies in this fashion. Owners of propane at the point of odorization are known and are already paying a fee. Moving the point of regulation to large emitters, the point of odorization, and transportation fuel blenders simplifies efforts to track and cap emissions and provides transparency for the allowance market. (WSPA1)

> **Response:** We believe that the point of regulation should be the LPG producer and importer, rather than owners of propane at the point of odorization. This is consistent with Federal reporting requirements; it also allows ARB to provide a level playing field for propane odorized in-state and propane odorized outside jurisdiction and imported to California.

E-15. Comment: The point of regulation for Natural Gas Liquids (NGL) should be at the point of combustion for large emitters or at the point of odorization for non-industrial use to avoid the potential for double counting or over-regulation. Any NGLs which are blended into transportation fuel should be treated in the same manner as petroleum transportation fuel. (WSPA1)

> **Response:** We disagree. For program simplicity and efficiency, the point of regulation for Natural Gas Liquids is at the supplier.

Biomass

E-16. Comment: Suppliers of biofuels should be able to apply for credits for certain fuels using an emission crediting system consistent with adopted emission factors, the best science, and verifiable methodologies. CARB's Low Carbon Fuel Standard is a good example of how credits for low-carbon fuels could be accounted for. (KUSTIN03, KUSTIN08)

> **Response:** Suppliers of biofuels that are identified by the source of fuel, as described in section 95852.2 of the cap-and-trade regulation, will be able to avoid a compliance obligation. Receiving any credits in addition to this would be considered double-counting, as they would be used to replace fossil fuel, thus being "credited" under a capped sector and credited for being a biofuel.

E-17. Comment: We strongly recommend that ARB require fuel providers to hold CO_2 emission allowances to cover the GHG emissions released into the atmosphere as a consequence of the use of transportation biofuels. (KUSTIN08)

> **Response:** Suppliers of biofuels will be held accountable for the fossil fuel portion of their emissions. Biomass-derived fuel emissions must be identified by the source of fuel as described in section 95852.2 of the cap-and-trade regulation. A biomass-derived fuel not listed in that section will be required to hold a compliance obligation under section 95852.1.

E-18. (multiple comments)
Comment: Ethanol made from cellulosic materials, corn starch, or sugar cane are all treated as "zero" emissions even though it is well understood that ethanol from these different sources result in dramatically different impacts on GHG emissions. The same is true for biodiesel derived from virgin oils, tallow, or waste oils. According to ARB's own analysis, ethanol made from corn starch can actually increase the amount of carbon dioxide released into the atmosphere. While ARB's analysis shows that both biodiesel and renewable diesel derived from soybeans provide small reductions in emissions, biomass-based diesel alternatives derived from sources such as palm oil grown on former tropical forest or peatland could substantially increase emissions. As a consequence, exempting all ethanol and biodiesel from carbon allowance obligations could have the perverse effect of incentivizing the greater use of ethanol and biodiesel, regardless of whether they can contribute to reduced GHG emissions or not. (KUSTIN08)

Comment: The policy exempting biofuels used for transportation from compliance obligations under certain conditions is not consistent with the goals of AB 32 because it would incentivize use of some fuels that are more carbon intensive on a life cycle basis or have other types of negative sustainability impacts. This would lead to an increase of emissions instead of incenting only those fuels that are less carbon intensive and result in lower emissions. The development of some rules for fuels under the cap and not others—particularly the treatment of biofuels—is handled unevenly, with specific regulations outlining the accounting process for biofuels used for transportation but no corresponding detail for the rest of the program. Because the other elements of the policy are not included we cannot evaluate the full impact of this language in context with the impacts of the full rule. We further recommend that ARB delete the policy on biofuels because it is not consistent with the goals of AB 32 and it is premature and inappropriate to add this biofuel regulatory language into the rule without providing the context for the other elements of the rule addressing transportation fuels. (CHEVRON1)

Comment: Regarding the exemption for fuel ethanol from a compliance obligation (section 95952.2(c)), no justification can be provided since ethanol introduction has many environmental impacts in California, the rest of the U.S., and internationally, since it greatly increases smog, water pollution, and causes displacement of better land uses. Emissions from fuel ethanol source categories as identified in sections 95100 through 95199 of the Mandatory Reporting Regulation count toward applicable reporting thresholds but do not count toward a covered entity's compliance obligation set forth in this regulation. (CBE1)

> **Response:** ARB's cap-and-trade requires all emissions from biomass combustion to be reported. California's Low Carbon Fuel Standard (LCFS) goes one step further in its GHG assessment for transportation fuels by addressing all lifecycle emissions (not just fossil fuel) in its regulation. The LCFS is expected to reduce the carbon intensity of transportation fuels 10 percent by 2020. Since GHG lifecycle emissions from transportation fuels are already regulated through the LCFS, biofuels do not need to be directly addressed in the cap-and-trade program. California's LCFS comes from Executive Order S-01-07, which mandates the establishment of a statewide goal to reduce the carbon intensity of California's transportation fuels by at least 10 percent by 2020. This standard applies to all transportation fuels unless otherwise noted in the regulation. Specifically with regard to transportation fuels, ethanol from biomass (Agriculture, Municipal, and Forestry) is covered under the LCFS, while biomass electricity is excluded from the regulation. This program is complementary to LCFS, as it provides incentives to develop less carbon-intense fuels by applying a compliance obligation to fossil fuels.

E-19. Comment: All technologies and land use choices must be evaluated on a level playing field, using rigorously developed and consistent scientific methodology that is uniformly applied. The PRO does not address the potential for the substantial expansion of the production of biofuels using single as well as multi-purpose crops that will likely enhance land productivity and further reduce lifecycle GHG emissions. (ERICKSON)

> **Response:** The cap-and-trade regulation only looks at direct reductions of fossil-fuel emissions at covered facilities from the increased use of biofuels, as this is the point at which there is a compliance obligation. All other benefits are considered, but not directly related to the scope of the regulation to address direct emissions at covered entities.

E-20. (multiple comments)
Comment: Treat emissions from all transportation liquid fuels equally and hold fuel providers accountable under the cap for the GHG emissions of all biofuels. The proposed regulations currently exempt emissions from all “biodiesel” and “fuel ethanol” and do not address any other type of biofuels. CARB’s own analysis points out that ethanol made from corn starch and biodiesel derived from soybeans can actually increase GHG emissions. If ethanol and biodiesel are exempted from compliance obligations this could actually incentivize their use despite their higher GHG content. We strongly recommend that CARB close the current biofuels loophole by accounting for emissions associated with biomass production and combustion. Without accurately accounting for the GHG impacts of biomass energy CARB runs the risk of creating a loophole of significant, uncounted increases in GHG emissions. We strongly recommend that CARB develop reporting requirements for biomass facilities and address the resulting emissions as they do for other generation sources. (ENVENTREP1, ENVENTREP2)

Comment: We strongly recommend that CARB treat emissions from all transportation liquid fuels equally and hold fuel providers accountable under the cap for the GHG emissions of all biofuels. The proposed regulations currently exempt emissions from all “biodiesel” and “fuel ethanol” and do not address any other type of biofuel. It is well understood, however, that GHG emissions resulting from the use of transportation biofuels varies dramatically depending on how the biofuel is produced. According to CARB’s own analysis, ethanol made from corn starch and biodiesel derived from soybeans can actually increase GHG emissions. As a result, exempting all ethanol and biodiesel from compliance obligations could have the perverse effect of incentivizing the greater use of all ethanol and biodiesel, regardless of whether it can contribute to reduced GHG emissions. We therefore urge CARB to require fuel providers to hold compliance instruments to cover the GHG emissions from transportation biofuels. It is critical to the integrity of the AB 32 program that CARB not create an emissions loophole by treating all transportation biofuels as “zero emissions.” (NRDC1)

Comment: ARB must close the biofuels loophole by requiring fuel providers to hold allowances to cover the greenhouse gas emissions released as a consequence of the use of transportation biofuels. The cap-and-trade rule should include GHG emissions from the combustion of transportation biofuels under the cap and require covered entities to obtain allowances for the emissions associated with the production and combustion of this material. It is well understood that CO_2 emissions as a result of using ethanol varies dramatically depending on how the ethanol is produced. This is also the case for other types of biofuels. Exempting all ethanol and biodiesel from carbon allowance obligations could have the perverse effect of incentivizing the greater use of ethanol and biodiesel, regardless of whether they can contribute to reduced GHG emissions or not. Consequently emissions from all transportation liquid fuels should be treated equally. Fuel providers should be held accountable under the cap for the carbon emissions of all biofuels. Suppliers of biofuels should be able to apply for credits for certain fuels, if at all, only by using a comprehensive and scientifically defensible emission crediting system that accurately captures the fuel's specific carbon footprint. (CBD1)

Comment: Emissions from biomass-derived fuels should have a compliance obligation under the cap that should reflect net emissions after both upstream and downstream emissions associated with the production and combustion of the fuel source have been taken into account. PFT recommends that ARB amend section 95852.2(a)(4)(A) of the Cap and Trade regulations and section 95852.2 et al. of the Mandatory Reporting Regulation (MRR) to include upstream biological emissions associated with land use impacts and the management of biomass feedstocks. The accounting and reporting guidance should be developed in 2011 prior to the regulations taking effect in 2012, and should require biomass fuel suppliers to report biological emissions associated with the feedstock. In the near term, CARB should require fuel users to report the origins of biomass for fuel. ARB staff should immediately begin the development of a clear reporting methodology that allows the forest biomass combusted for energy to be tracked back to a specific forest project. Section 95852.2(a)(4) of the Cap and Trade regulation should be amended to include this new reporting requirement. Section 958452.2 of the Mandatory Reporting Regulation should also be amended to reflect this reporting requirement, and in the period until this guidance is developed, the MMR should require facilities to report the source and volume of any forest biomass combusted. There should also be monitoring of where the source materials are coming from so you could distinguish between biomass material that is a benefit versus that which is creating a greater carbon debt. If ARB decides they don't want to put biomass into the cap we would urge you to at the very least make sure that you're getting good monitoring and reporting of where the material is coming from so you could monitor whether the lack of a compliance obligation creates an incentive for mining the forests for exact carbon to create that energy and so you can keep track and potentially use adaptive management if you do need to take steps to bring biomass under the cap. (PFT1, PFT2)

Comment: The proposed rules potentially create a double "freebie" for biomass combustion: an exemption from compliance obligations, coupled with a program for distributing free allowances for that same combustion that may be sold into the market and used to justify emissions at other facilities. This double "freebie" not only incentivizes biomass and biofuels use, but also risks a form of allowance double-counting that could ultimately increase GHG emissions overall. (CBD1)

Comment: Emissions from bioenergy, whether from combustion to generate electricity or from liquid transportation fuels, should be under the cap and should not be exempted from compliance obligations. As ARB has recognized in its Low Carbon Fuel Standard, biofuels vary widely in their life-cycle greenhouse gas emissions. The cap and trade rule should provide incentives for the lowest-carbon fuels, rather than blanketly exempting all bioenergy. The biomass exemption provides a perverse incentive to cut down forests, with all of their sequestered carbon, for energy purposes, which would actually make global warming worse. (SIERRACLUBCA4)

Comment: While we support the development of biomass energy and fuels from forests, careful consideration should be given to the GHG and environmental impacts that could result upstream from the production of the feedstock. The final proposed cap and trade regulations exempt forest biomass energy and fuels from the cap and only require the reporting of GHG emissions associated with the combustion of biomass without inclusion of upstream impacts. Yet, biomass energy and fuels, depending on the land use and management impacts upstream, can result in increased biological GHG emissions from the landscape as well as additional indirect emissions from energy use. The potential upstream land use impacts of biomass energy and fuels for a cap and trade program are comparable to those associated with the production of biofuels for California's Low Carbon Fuel Standard (LCFS). CARB has been and continues to invest considerable time and effort to account for indirect land use impacts, GHG emissions and sustainability for forest biofuels in its LCFS. Given the similarity in upstream accounting issues and potential environmental impacts with respect to biomass energy and fuels in the cap and trade program, the GHG treatment and sustainability considerations should be consistent across programs. TNC recommends that ARB amend section 95852.2 (a)(4)(A) of the cap and trade regulations and section 95121 et al. of the Mandatory Reporting Regulation to include upstream biological emissions associated with the land use impacts and management of feedstock. The accounting and reporting guidance should be developed in 2011 prior to the regulations taking effect in 2012 and should require biomass fuel suppliers to report biological emissions associated with the feedstock. In the near term, CARB should require fuel users to report the origins of biomass for fuel. The sustainability standard developed pursuant to the LCFS should also apply to the biomass used for energy within the cap and trade program. Also, TNC recommends the inclusion of biomass energy and fuels in the cap. The combustion of biomass results in greenhouse gas emissions and may not be offset by regrowth or maintenance of feedstock (e.g., forests) upstream. To maintain an incentive for biomass energy and fuels, compliance obligations may be freely allocated. However, this free allocation should be contingent upon proper evaluation and accounting of upstream biological emissions and sustainability criteria, as well as benchmarking based on best practices for the industry, as discussed earlier in our recommendations. (NC1)

Comment: ARB should begin work, including collaboration with EPA and other stakeholders and experts, to develop scientifically defensible quantitative assessments and reporting requirements by 2015 to evaluate the net carbon flux from the harvest and combustion of biomass-derived fuels. CARB should consider easing the reporting and tracking requirements to allow landowners and biomass users to easily certify the source of their biofuel, thus streamlining the program and creating stronger incentives to utilize the best biomass available. (EDF1)

Comment: Emissions from bioenergy produced through use biomass derived fuels, including especially forest biomass, and "wood and wood wastes" identified in section 95852.2(a)(4), should, as a default matter, be included under the cap and generate compliance obligations. Entities combusting these fuels should be excused from compliance obligations only to the extent that they can demonstrate that the production and use of the biomass fuel resulted in reduced or avoided greenhouse gas emissions over a timeframe relevant to AB 32, that is, by 2020. To this end, ARB should begin work, including collaboration with relevant stakeholders and experts, to develop scientifically defensible quantitative assessments reporting requirements to evaluate the net carbon flux associated with harvest and combustion of different biomass-derived fuels. Exemptions from compliance obligations should be based on the use of agency approved models and reporting requirements and should be limited to fuel sources that result in zero or negative total GHG emissions, such as food waste digesters.

Developing a transparent carbon accounting framework based on geographic and operational origin of forest biomass materials is critical if ARB and covered entities are to develop a scientifically defensible methodology for bioenergy under the cap and trade regulation. Such a program should include information associated with the production of biomass material (i.e. allowing for tracking from the point of combustion back to the point of production). However, in order to ensure the program is of reasonable size and scope, and doesn't create a costly disincentive to utilize biomass overall, CARB should consider easing the reporting and tracking requirements for certain sources of bioenergy where there is clarity on atmospheric carbon flux values. In such circumstances, CARB could allow landowners or biomass users to certify the source of their bioenergy and utilize lookup tables with default emissions factors and carbon flux values. (KUSTIN05)

Comment: The proposed regulations provide a significant incentive to produce energy from forest materials by exempting biomass facilities from compliance obligations. Exempting these categories from compliance obligations is equivalent to assigning a net carbon impact of zero to the growth, harvest, production, and NRDC Letter to CARB re Cap and Trade combustion of these fuel sources. In effect, the rule assumes, without justification, the "carbon neutrality" of all biomass fuels. Failure to accurately account for the GHG impacts of biomass energy incurs the risk of significant, uncounted increases in GHG emissions. We strongly recommend that CARB commit to both developing reporting requirements for biomass facilities and to addressing the resulting emissions, if any, in a manner consistent with other generation sources in the AB 32 regulatory framework. (NRDC1)

Comment: California's cap and trade program would create an incentive to use biomass and biofuels whether or not they do in fact produce fewer emissions than the fossil fuels they would replace. The implicit subsidy such a program would create would effectively result in a form of emissions leakage from capped to uncapped energy sources and significantly erode the emission reductions that CARB intends the program to achieve. (EDF1)

Comment: CARB should seek input from a broad range of stakeholders and develop a program that allows for the accurate quantification of net carbon fluxes into and out of the atmosphere from the use of biofuels. (EDF1)

Comment: It is inappropriate to only measure the GHG emissions at the smokestack and ignore landscape implications of biomass utilization. This option fails to account for the potentially lower emissions profile of some biomass sources compared to fossil fuels, while also ignoring the very real potential for higher total net emissions from biomass relative to fossil fuels depending on the source and production practices and time frame of analysis. (EDF1)

Comment: We support the inclusion of carbon flux calculations into the rule; we also realize that CARB currently does not have the accounting and reporting framework in place to make that inclusion possible. We encourage CARB to develop an appropriate framework and to seek input from a broad array of stakeholders. (EDF1)

Comment: Different forest biomass feedstocks and their management can incur very different "carbon debts" over different time scales. As currently written, the cap and trade rule provides a significant incentive to produce biomass energy from forest materials through the exemption, but does not provide the accounting infrastructure to require or ensure that the emissions from the combustion of these materials are carbon neutral within the timeframe relevant to AB 32. Of course, in some instances the use of biomass to make energy will result in "de minimus" or net carbon negative emissions (i.e. biomass fired power plants that burn only agricultural wastes which otherwise would be burned in the open or anaerobic digesters that handle food waste). Other examples may include use of harvest or mill residue for bioenergy. However, in other cases, such as conversion of standing forests to bioenergy without forest replacement, the production of biomass based energy could cause an increase in overall GHG emissions in the atmosphere. The cap and trade regulation currently before the board represents an opportunity to promote and reward the use of fuels that provide the most emissions reductions while moving away from biomass that can increase overall greenhouse gas emissions, such an opportunity should not be missed. (KUSTIN05)

Comment: Close the biomass biofuels loopholes. Emissions from bioenergy, whether from combustion to generate electricity or from liquid transportation fuels, should be under the cap and should not be exempted from compliance obligations. As ARB has recognized in its Low Carbon Fuel Standard, biofuels vary widely in their life-cycle greenhouse gas emissions. The cap-and-trade rule should provide incentives for the lowest-carbon fuels, rather than blanketly exempting all bioenergy. The biomass exemption provides a perverse incentive to cut down forests, with all of their sequestered carbon, for energy purposes, which would actually make global warming worse. (SIERRACLUBCA4)

Comment: We understand that ARB may be assuming that future carbon sequestration associated with overall statewide forest growth will offset any emissions from combustion of woody biomass fuels. Such an assumption does not support a wholesale exemption from compliance obligation as currently proposed, but rather, supports the development of a quantitative framework to measure and verify this phenomenon. To the extent that harvesting biomass affects overall carbon stocks and the overall rate of sequestration, all bioenergy should not be considered inherently "carbon neutral," but rather, should generate a carbon debt that must be considered. Thus, the timeframe over which a particular harvested area can re-sequester the carbon associated with biomass removal is essential to understanding the carbon implications of the particular fuels. It is important to note that any re-sequestration must be equal to the sequestration that would occur under a business-as-usual scenario for a net carbon value of zero.

Developing a transparent carbon accounting framework based on geographic and operational origin of forest biomass materials is critical if ARB and covered entities are to develop a scientifically defensible methodology for bioenergy under the cap and trade regulation. Such a program should include information associated with the production of biomass material (i.e., allowing for tracking from the point of combustion back to the point of production). (KUSTIN06)

Comment: We request that ARB adjust the treatment of energy produced from biomass (in particular—forest biomass) in the Cap and Trade rule to include this source under the cap and account for greenhouse gas emissions associated with the production and combustion of this material. (KUSTIN06)

Comment: Under the Clean Air Act, U.S. EPA correctly determined that biogenic emissions should be considered when evaluating whether facilities are subject to the Prevention of Significant Deterioration and Title V Programs. Once facilities are subject to these federal provisions they trigger additional control requirements and regulatory oversight. If California were to accurately incorporate biomass emissions into the cap and base compliance requirements based on those emissions, the program would complement EPA's effort to accurately account for emissions, and would create an incentive to identify and reward use of the lowest carbon biomass available. (KUSTIN06)

Comment: ARB has not explicitly made a determination regarding the overall carbon impacts of these fuel sources and does not provide explicit explanation for the exemption. However, exempting these categories from compliance obligations is equivalent to assuming an identical flux of carbon into and out of the atmosphere associated with all biomass growth, harvest, production, and combustion. In effect, by exempting bioenergy, the rule assumes "carbon neutrality" for all biomass fuels, which is not scientifically accurate. Rather, different forest biomass feedstocks and their management can incur very different "carbon debts" over different time scales. As currently written, the Cap and Trade rule provides a significant incentive to produce biomass energy from forest materials through the exemption, but does not provide the accounting infrastructure to require or ensure that the emissions from the combustion of these materials are carbon neutral within the timeframe relevant to AB 32. Of course, in some instances the use of biomass to make energy will result in "de minimus" or net carbon negative emissions (i.e. Biomass fired power plants that burn only agricultural wastes which otherwise would be burned in the open or anaerobic digesters that handle food waste). Other examples may include use of harvest or mill residue for bioenergy. However, in other cases, such as conversion of standing forests to bioenergy without forest replacement, the production of biomass based energy could cause an increase in overall GHG emissions in the atmosphere. The cap and trade regulation currently before the board represents an opportunity to promote and reward the use of fuels that provide the most emissions reductions while moving away from biomass that can increase overall greenhouse gas emissions—such an opportunity should not be missed. Accordingly, emissions from bioenergy produced through use biomass derived fuels—including especially forest biomass, and "wood and wood wastes" identified in section 95852.2(a)(4)—should, as a default matter, be included under the cap and generate compliance obligations. Entities combusting these fuels should be excused from compliance obligations only to the extent that they can demonstrate that the production and use of the biomass fuel resulted in reduced or avoided greenhouse gas emissions over a timeframe relevant to AB 32, that is, by 2020. To this end, ARB should begin work, including collaboration with relevant stakeholders and experts, to develop scientifically defensible quantitative assessments reporting requirements to evaluate the net carbon flux associated with harvest and combustion of different biomass-derived fuels. Exemptions from compliance obligations should be based on the use of agency approved models and reporting requirements and should be limited to fuel sources that result in zero or negative total GHG emissions, such as food waste digesters. (KUSTIN06)

Comment: With respect to biomass energy and fuels, we do support biomass for these purposes. However, we do also believe that the combustion of biomass and the associated greenhouse emissions should have compliance associated with it. While the combustion may be offset by forest regrowth upstream, there is not a guarantee you could have emissions that increase upstream to produce the materials for combustion downstream. (NC6)

Comment: The proposed exemption for biogenic emissions must be eliminated. The ISOR fails to explain the exemption for biogenic emissions. Among other things, an ISOR must include a "statement of the specific purpose" of each proposed regulation and "the rationale for the determination by the agency that [each proposed regulation] is reasonably necessary to carry out the purpose for which it is proposed." (Gov. Code section 11346.2(b)(1)) The ISOR also must identify "each technical, theoretical, and empirical study, report, or similar document" on which ARB relies in proposing the regulation. (Gov. Code section 11346.2(b)(2)). Furthermore, the ISOR must describe "reasonable alternatives to the regulation and the agency's reasons for rejecting those alternatives." (Gov. Code section 11346.2(b)(3)). The ISOR fails to comply with these requirements of law. Nowhere does the ISOR explain why the proposed regulation, at section 95852.2, exempts virtually all combustion emissions from biogenic sources from compliance obligations. Nor does the ISOR identify any technical, theoretical, or empirical support for the exemption. By the same token, the ISOR fails to describe any alternative approaches to the exemption or ARB's reasons for rejecting them. Without an understanding of ARB staff's rationale for the exemption, neither the public nor decision-makers can assess whether it is consistent with the purpose of AB 32 or participate meaningfully in the public process surrounding adoption of the regulation. Accordingly, staff's failure to explain the reasoning behind the exemption constitutes a substantial failure to comply with the Administrative Procedure Act. *See* Gov. Code section 11350. (CBD1)

Comment: The proposed exemption for biogenic emissions must be eliminated. Biomass and biofuels emissions do not necessarily displace fossil fuel emissions. Another common assumption of carbon neutrality proponents is that biomass and biofuels combustion by definition displaces fossil-fuel combustion. In other words, this carbon neutrality theory hinges on the belief that for each ton of biomass burned, an equivalent amount of fossil fuel is not burned, and any resulting fossil GHG emissions are therefore completely avoided. Like other assumptions underlying the carbon neutrality argument, this assumption lacks a sound basis in fact. First, the assumption of one-to-one displacement does not account for growth in demand for energy or other products, but rather seems to assume a flat demand curve. Population and economic growth, however, will generally cause increases in demand, even as energy use and manufacturing become more efficient. As a result, biomass may simply be adding capacity rather than displacing capacity currently satisfied by fossil fuels. Second, in the energy sector, it cannot be assumed that future demand will automatically be satisfied by fossil-fired, carbon-intensive generation. Rightly or wrongly, biomass energy is widely considered to be renewable energy, and thus competes with other renewables for subsidies, incentives, and market share within renewable portfolio standards and renewable electricity standards. Accordingly, to the extent that biomass generation adds capacity to serve future demand in the context of a renewable energy standard, it may well displace other renewables (such as wind and solar, which tend to be more expensive per unit of energy generated) rather than fossil fuels, resulting in dramatically increased carbon emissions per megawatt of energy produced. Determining whether and to what extent biomass generation replaces fossil-fired generation thus requires a facility-specific analysis of energy market characteristics and conditions. It cannot simply be assumed that every ton of biogenic carbon replaces a ton of fossil carbon that would otherwise enter the atmosphere. (CBD1)

Comment: The proposed exemption for biogenic emissions must be eliminated—renewability and sustainability standards do not necessarily provide good proxies for climate analysis. For the most part, existing sustainability and renewability standards exist primarily to incentivize particular forms of energy generation, and are not good proxies for analysis of the carbon footprint of a particular biomass-burning facility. These standards thus typically reflect political and economic rather than primarily scientific or technology-based considerations. Such standards also may create perverse incentives that lead to other unacceptable environmental effects; as discussed in the Manomet Report and elsewhere, increased demand for biomass fuels can result in vastly increased levels of whole-tree harvest and even large-scale conversion of natural forests to energy crops. Moreover, existing sustainability standards tend to ignore critically relevant time-scale and carbon debt questions; as previously discussed, a biomass harvesting regime that is technically "sustainable" or "renewable" on a scale of decades or centuries will still contribute significantly to climate impacts.

Limitations on "wood and wood waste" within the proposed cap and trade regulation, which appear to have been modeled on previous definitions of "renewable" biomass under California law, provide an excellent illustration of this problem. Combustion of wood harvested in accordance with a "timber management plan" or other "locally or nationally approved plan," for the purpose of "forest fire fuel reduction or forest stand improvement," would be eligible for the exemption from compliance obligations. Yet these standards say absolutely nothing about the relative carbon intensity of the fuels or the relative carbon debts associated with their removal, and thus do not provide an adequate proxy for analysis of "carbon neutrality."

Furthermore, even to the extent that removal of "hazardous fuels" or insect-infested stands might be intended to prevent emissions associated with wildfire or widespread forest decay, it is not accurate to assume that removal and combustion of these fuels simply avoids identical emissions that would have occurred anyway. It is true that combustion of trees, brush, and litter in forest fires releases carbon emissions. Yet the emissions from fires may be far lower (and far fewer live trees may be killed) than previously believed, depending upon forest type and fire intensity. Indeed, significant amounts of carbon remain sequestered in forest pools following even high-intensity wildfires. Carbon lost in fires also may rapidly be resequestered by early successional species following disturbance.

In fact, recent scientific studies call into question the entire enterprise of removing (and burning) biomass in order to avoid carbon emissions associated with wildfire:

> [F]uel removal almost always reduces carbon storage more than the additional carbon that a stand is able to store when made more resistant to wildfire. Leaves and leaf litter can and do have the majority of their biomass consumed in a high-severity wildfire, but most of the carbon stored in forest biomass (stem wood, branches, coarse woody debris) remains unconsumed even by high-severity wildfires. For this reason, it is inefficient to remove large amounts of biomass to reduce the fraction by which other biomass components are consumed via combustion.

Accordingly, it is not accurate to assume that the carbon emissions associated with biomass energy production would have occurred in the forest anyway, on the same time scales and to the same degree, as a result of fire. In reality, biomass combustion ensures that forest biomass is converted into carbon dioxide on a very short time scale, whether or not similar emissions would have occurred as a result of fire, and regardless of whether logging is as effective as natural succession in facilitating sequestration of those emissions. Current scientific work also indicates that fire, even the high-intensity variety, is a natural event that we should accept and encourage, not attempt to forestall through speculative, intensive, and destructive logging projects aimed at “forest cleaning” or “fuel reduction.” The dead trees left standing after a high-intensity fire provide critical wildlife habitat as well as soil nutrients that encourage rapid growth of early successional species. Moreover, unlike emissions produced in biomass energy facilities, carbon in standing dead trees and forest floor pools may remain sequestered for a long time following even a high-intensity fire, and decays slowly into the atmosphere even as new plant growth recolonizes a burned area. (CBD1)

Comment: The proposed exemption for biogenic emissions must be eliminated. ARB must close the biomass loophole by including bioenergy emissions under the cap and accounting for the greenhouse gas emissions associated with biomass production and combustion.

The cap and trade rule should include the GHG emissions from the combustion of biomass (in particular, forest biomass) under the cap and require covered entities to obtain allowances for the emissions associated with the production and combustion of this material.

Section 95852.2 exempts a number of fuel source categories from compliance obligations. Exempted categories include direct combustion of several sources of cellulosic biomass, including solid waste, construction and manufacturing debris, mill residues, range land maintenance residues, all agricultural crops or waste, and wood or wood waste. Covered entities must report emissions from the combustion of these fuels but are not required to obtain allowances for those emissions. Furthermore, neither users nor suppliers of biomass for energy are required to identify the sources of biomass material or report the biological greenhouse gas impacts associated with the removal of biomass for energy or fuel.

As explained in the preceding section, ARB has not explicitly made a determination regarding the overall carbon impacts of these fuel sources and does not provide any explicit explanation for the exemption. However, exempting these categories from compliance obligations is equivalent to assuming an identical flux of carbon into and out of the atmosphere associated with all biomass growth, harvest, production, and combustion.

Accordingly, emissions from bioenergy produced through combustion of biomass, derived fuels, including especially forest biomass, and “wood and wood wastes” identified in section 95852.2(a)(4), should, as a default matter, be included under the cap and generate compliance obligations. Entities combusting these fuels should be excused from compliance obligations only to the extent that they can demonstrate that the production and use of the biomass fuel resulted in reduced or avoided greenhouse gas emissions over a timeframe relevant to AB 32, that is, by 2020. (CBD1)

Comment: The proposed exemption for biogenic emissions must be eliminated. Biomass combustion is not “carbon neutral.” The unchecked expansion of biomass energy, particularly the use of woody biomass to generate electricity, represents a double threat to the climate and to California’s forests. Although scientists and policy-makers have now thoroughly debunked the long-standing myth that biomass combustion is “carbon neutral,” industry proponents continue to seek special treatment for biomass projects based on the dangerously false contention that biogenic GHG emissions do not affect the climate. Public incentives for biomass, embodied in renewable energy standards and other policies, are both threatening to exacerbate greenhouse pollution and putting increased pressure on the nation’s forests by increasing the demand for woody fuel. The proposed cap and trade regulation, with its blanket exemption for biomass and biofuels, would create another powerful incentive for biomass development in California.

Biomass combustion causes GHG emissions, particularly of CO_2. Indeed, CO_2 emissions from electrical generating units burning woody biomass rival or exceed those of coal-burning facilities, and are nearly double those of facilities burning natural gas. CO2 from fossil sources shares the same physical characteristics and same climate-forcing properties as CO_2 from biogenic sources. There is no physical, chemical, or climate-forcing difference between fossil CO_2 and biogenic CO_2. Put simply, CO_2 is CO_2. Infrared radiation does not and cannot discriminate among the identical molecules of CO_2 circulating in the atmosphere.

There is thus no basis in law, science, or sound policy for exempting sources of biogenic GHG emissions from compliance obligations. These emissions affect California’s ability to achieve AB 32’s objectives just as much as emissions from other sources. Moreover, the climate impacts of any particular biomass facility will vary greatly, depending on fuel characteristics and sources, secondary emissions associated with harvesting and processing, land use impacts, and effects on future sequestration. In effect, the degree to which a particular biomass project might plausibly claim to be “carbon neutral,” and the time it might take to achieve neutrality, cannot be known absent a complete lifecycle analysis considering all of these factors and variables. It is this type of analysis, not an unexplained and unsupportable blanket exemption for biomass emissions, which ARB should be developing as part of this regulation.

Neither the ISOR nor the FED offers any insight into why the proposed regulation exempts biomass emissions from compliance obligations. The obvious implication from this silence is that ARB staff views biomass combustion as “carbon neutral,” although neither document explains the theory behind this belief. Whatever the theory, this view is not supported by the facts. (CBD1)

Comment: The proposed exemption for biogenic emissions must be eliminated—biogenic emissions are not automatically carbon-neutral. Some biomass proponents claim that all biogenic GHG emissions are part of a “natural” carbon cycle that by definition cannot have any effect on the climate. Under this theory, burning biomass releases carbon that was removed from the atmosphere by the fuels as they were growing, and thus completes a “natural” cycle by returning that carbon to the atmosphere.

This theory is facially and dangerously incorrect. Taken to its logical conclusion, this theory would hold that deforestation has no effect on climate change. Indeed, under a literal application of this theory, every single tree, shrub, and blade of grass on earth could be burned tomorrow and converted into CO_2 with no discernible effect on the climate.

Scientists and policy-makers agree, however, that deforestation—which necessarily entails conversion of sequestered biogenic carbon into atmospheric CO_2 does contribute to climate change. Ten to 15 percent of global carbon emissions result from deforestation and forest degradation, primarily in the tropics. These emissions are estimated at between 1,400 and 2,000 Tg per year. Although U.S. forests are generally considered a net carbon sink, this may be true only due to significant global leakage related to domestic demand for wood and agricultural products. GHG emissions associated with these losses are significant contributors to climate change notwithstanding their “biogenic” character.

The “natural carbon cycle” theory also ignores the fact that a tremendous amount of primary forest, representing a huge proportion of historic biogenic carbon stores, has been lost during the last few centuries. According to recent maps compiled by the World Resources Institute, only 21 percent of the world’s forests are “intact,” and 47 percent have been lost entirely. Between 1850 and 2000, global land use change caused emissions of 156,000 Tg of carbon, mostly from deforestation. Recent studies indicate that the density of remaining forest cover may be lower and far more variable than previously thought. The United States has also experienced the greatest loss of forest cover, as a proportion of forest cover in the year 2000, of any country with more than one million square kilometers of forest. This historic and continuing loss of forest biomass, much of which has been burned or otherwise converted into atmospheric carbon pollution, represents a tremendous existing carbon debt, one that further emissions of biogenic carbon can only increase. To extend the metaphor, continuing to burn trees for energy isn’t like balancing a checkbook. It’s like taking out another mortgage on a house that’s already far underwater.

Furthermore, it makes no sense to assume that all currently existing trees and other plants are composed solely of “biogenic” carbon. More than two centuries of increasing fossil GHG emissions have accumulated in the atmosphere. Given these pollutants’ atmospheric lifetimes, and considering the lifespan of many trees and plants, it is safe to assume that some considerable portion of this fossil carbon has been resequestered in currently existing biomass. Technically, therefore, burning that biomass may be returning fossil carbon to the atmosphere, again increasing the overall planetary carbon imbalance relative to pre-industrial conditions. Above all, this example demonstrates that it makes little scientific sense to divide carbon into theoretical “fossil” and “biogenic” pools for the purpose of assuming simplistically that biogenic carbon is part of some natural cycle that cannot affect the climate. Whatever natural biogenic carbon cycle existed prior to the industrial revolution has been radically altered by deforestation, land use change, and fossil carbon emissions.

The extent and duration of the effects of global warming will be determined largely by the degree to which anthropogenic sources of GHGs, particularly CO_2, continue to exceed the capacity of the Earth's carbon sinks for reabsorption—in other words, by the cumulative total of anthropogenic greenhouse pollutants in the atmosphere. Every ton of CO_2 counts toward this total, regardless of what was burned to produce it. Every ton of CO_2 similarly counts toward California's effort to meet the statutory goals of AB 32. Broad exemptions from compliance obligations for large categories of emissions facilitate near-term GHG pollution and interfere with these goals. (CBD1)

Comment: The proposed exemption for biogenic emissions must be eliminated. Biomass combustion creates a "carbon debt" that can last for decades or even centuries. Under another common theory advanced by proponents of biomass energy, biomass burning should be considered carbon neutral because any GHG emissions will be reabsorbed by future plant growth that replaces the harvested fuel. Yet carbon emitted during biomass combustion may remain in the atmosphere for decades or centuries before being resequestered.

Another version of this theory assumes that the emissions from present combustion and future decomposition are roughly the same, and thus concludes that combustion has a "net zero" emissions profile. ARB staff articulated this theory, albeit in a conclusory and unsupported fashion, in the ISOR for the Renewable Electricity Standard.

Both versions of the theory ignore the critical temporal relationships between present carbon emissions and the future effects of global warming and climate change. In other words, because meeting (or exceeding) atmospheric CO_2 targets has a strong temporal element, the time that it takes for CO_2 released into the atmosphere today to be reabsorbed is of critical importance in assessing the climate impacts of carbon emissions. By the same token, the carbon in living and dead biomass will remain sequestered in various pools (including forest soils) for a significant amount of time, whereas combustion immediately converts all of that carbon to atmospheric GHGs. This time lag has been identified in several recent studies as the source of a "carbon debt" that varies by fuel source, technology, and comparison to the fossil fuels assumed to be displaced by bioenergy generation.

The biomass carbon debt is especially pronounced when trees are burned for energy. Scientists agree that "[t]he amount of carbon sequestered by forest ecosystems plays an important role in regulating atmospheric levels of carbon dioxide." The removal and processing of forest biomass reduces storage in forest carbon pools and results in short-term emissions of greenhouse gases, even when some of that biomass remains sequestered for a period of time in commercial forest products. According to recent studies, "[t]ypically 30–50 percent of the harvested C is lost in manufacturing and initial use, a loss that is larger than could be expected from even the most extreme forest fire." Where harvested biomass is combusted for energy, rather than processed into wood products, short-term emissions are necessarily far greater, and long-term sequestration in forest products is eliminated altogether.

In addition to converting woody biomass into CO_2, thinning and post-fire salvage operations for bioenergy production also reduce the future carbon sequestration potential of the affected forest stand by removing trees that otherwise would have continued to draw CO_2 from the atmosphere. Surveys of the world's most carbon-dense forests, including the moist temperate conifer forests of North America, have confirmed that the greatest accumulations of biological carbon occur in the absence of human land-use disturbance.

Removal of forest biomass also affects long-term carbon storage in forest soils. Thinning and harvesting operations can reduce carbon inputs to soils and stimulate soil respiration, resulting in both reduced soil sequestration and near-term emissions. A recent meta-analysis of logging impacts in temperate forests showed that harvesting reduced soil carbon by an average of eight percent; depending on soil type, forest composition, and harvest method, some losses were as high as 36 percent. Other studies have shown that forests remain net sources of carbon emissions for more than a decade after logging operations, primarily due to increased soil respiration. Fuel treatments that change the amount and composition of decomposing forest biomass can influence long-term below-ground carbon storage.

The time between harvest and complete reabsorption of all this lost carbon by a forest stand, the duration of the "carbon debt", can span decades or even centuries. For example, one recent study concluded that even assuming perfect conversion of biomass to energy and a one-to-one displacement of fossil-fired generation, it still took from 34 to 228 years for forests in the western U.S. to reach carbon neutrality for biomass used directly for energy generation, and between 201 and 459 years if the biomass was converted to biofuels (the ranges depending upon the characteristics of the trees, forests and fire return intervals). Accordingly, because forest biomass utilization is not carbon neutral in the near term, the near-term effects of carbon emissions associated with biomass combustion must be considered.

This is especially important here because the primary goal of AB 32, reducing California's GHG emissions to 1990 levels by 2020, is a near-term goal. Accordingly, excessive near-term emissions will likely impede achievement of this goal. Moreover, at a global level, near-term GHG emissions exacerbate the risk of increasing atmospheric concentrations of greenhouse pollutants to the point where severe impacts are unavoidable, the so-called climate "tipping point." It is well established as a matter of science and policy that in order to avoid the worst impacts of global warming and climate change, global temperatures must not be allowed to exceed 2°C over pre-industrial levels. Whether we exceed the 2°C threshold depends on the level at which atmospheric CO_2 levels are eventually stabilized, which in turn depends on total cumulative anthropogenic GHG emissions. The greater the CO_2 levels, the greater the risk of exceeding this threshold and triggering likely catastrophic climate changes. The probability of overshooting 2°C is as follows according to Hare and Meinshausen (2006):

85 percent (68-99 percent) at 550 ppm CO_2 eq (= 475 ppm CO_2)
47 percent (26-76 percent) at 450 ppm CO_2 eq (=400 ppm CO_2)
27 percent (2-57 percent) at 400 ppm CO_2 eq (= 350 ppm CO_2)
8 percent (0-31 percent) at 350 ppm CO_2 eq

According to these scientists, "[o]nly scenarios that aim at stabilization levels at or below 400 ppm CO_2 equivalence (~350 ppm CO_2) can limit the probability of exceeding 2°C to reasonable levels." But in order to achieve stabilization levels that avert the worst impacts of climate change, emissions must peak by about 2015, and must decline very rapidly thereafter.

In short, minimizing CO_2 emissions in the next few years is critically important to meeting both AB 32's goals and global climate targets, even if some of all of that CO_2 might in theory be reabsorbed from the atmosphere in the decades or centuries to come. The science makes clear that the time frame for resequestration of CO_2 emitted from forest biomass combustion is on the order of decades or centuries, not years. Indeed, in evaluating carbon emissions from other biofuels, independent scientists have begun to develop strategies for evaluating the carbon impacts of biofuels in relation to the high social and environmental cost of short-term emissions. Even EPA has begun to recognize the importance of this temporal analysis in other contexts. Short-term CO_2 emissions from woody biomass combustion are thus significant, not "neutral", in the context of efforts to avoid the worst impacts of climate change, and should be treated as such for purposes of AB 32 as well.

Even if regeneration of a biomass fuel may one day repay the carbon debt incurred when it was first burned, the greenhouse pollution emitted upon combustion will act to warm the atmosphere for years, decades, or centuries in the meantime. Put another way, even if a particular biomass fuel may one day arguably become carbon neutral, its emissions are not climate neutral in the interim. Rather, they exert a warming effect on the climate and contribute to the total cumulative accumulation of GHGs in the atmosphere that will determine not only California's success or failure in meeting the goals of AB 32, but also humanity's success or failure in heading off the worst impacts of climate change. (CBD1)

Comment: The proposed exemption for biogenic emissions must be eliminated. National-level reporting and inventory programs provide no basis for exemptions at the facility scale. Industry proponents also often claim that counting and regulating biomass emissions at the facility level would contradict GHG reporting and inventory methodologies adopted by the Intergovernmental Panel on Climate Change (IPCC) and Environmental Protection Agency, both of which treat biomass emissions as carbon neutral. Scientists, however, have called into question whether biomass emissions should be considered carbon neutral even at the national inventory scale. The "accounting error" that assumes carbon neutrality for biomass power is based on a misreading of internationally accepted carbon accounting standards promulgated by the Intergovernmental Panel on Climate Change (IPCC). These rules count any harvesting of wood as a direct and immediate emission of carbon dioxide to the atmosphere at the time of harvesting. These emissions are only considered to be re-sequestered following the slow, often multi-decade regrowth of cut forests. Emissions released when biomass power plants actually burn this fuel are not counted under IPCC rules in order to avoid double counting. The U.S. EPA and other institutions that track carbon emissions have misinterpreted this accounting rule. The EPA does not count stack emissions when biomass is burned for power generation, but it also does not account for emissions at the time of harvesting. The result is that emissions from biomass power are never counted. The better solution is to focus first on carbon emissions from the smokestack, and then to factor in emissions and reductions associated with land use change and other relevant considerations. Compliance obligations for biomass emissions under the cap and trade program, which measure emissions first and foremost at the stack, are consistent with this good accounting practice. (CBD1)

Comment: The proposed rules potentially create a double “freebie” for biomass combustion: an exemption from compliance obligations, coupled with a program for distributing free allowances for that same combustion that may be sold into the market and used to justify emissions at other facilities. This double “freebie” not only incentivizes biomass and biofuels use, but also risks a form of allowance double-counting that could ultimately increase GHG emissions overall. (CBD1)

Comment: Forest biomass energy and fuels should be included within the cap and mandatory reporting should include upstream impacts to the land base. While TNC supports the development of biomass energy and fuels from forests, careful consideration should be given to the GHG and environmental impacts that could result upstream from the production of the feedstock. Biomass energy and fuels, depending on the land use and management impacts upstream, can result in increased biological GHG emissions from the landscape as well as additional indirect emissions from energy use. The potential upstream land use impacts of biomass energy and fuels for a cap and trade program are comparable to those associated with the production of biofuels for California’s Low Carbon Fuel Standard (LCFS). CARB has been and continues to invest considerable time and effort to account for indirect land use impacts, GHG emissions and sustainability for forest biofuels in its LCFS. Given the similarity in upstream accounting issues and potential environmental impacts with respect to biomass energy and fuels in the cap and trade program, the GHG treatment and sustainability considerations should be consistent across programs. TNC recommends that ARB amend section 95852.2(a)(4)(A) of the cap and trade regulations and section 95852.2 et al. of the Mandatory Reporting Regulation to include upstream biological emissions associated with the land use impacts and management of feedstock. The accounting and reporting guidance should be developed in 2011 prior to the regulations taking effect in 2012 and should require biomass fuel suppliers to report biological emissions associated with the feedstock. In the near term, CARB should require fuel users to report the origins of biomass for fuel. The sustainability standard developed pursuant to the LCFS should also apply to the biomass used for energy within the cap and trade program. Also, TNC recommends the inclusion of biomass energy and fuels in the cap. The combustion of biomass results in GHG emissions and may not be offset by regrowth or maintenance of feedstock (e.g., forests) upstream. To maintain an incentive for biomass energy and fuels, compliance obligations may be freely allocated. However, this free allocation should be contingent upon proper evaluation and accounting of upstream biological emissions and sustainability criteria, as well as benchmarking based on best practices for the industry, as discussed earlier in our recommendations. (NC2)

> **Response:** ARB wants to correctly identify and separately treat biomass-derived fuels from fossil fuels. Section 95103(j) of the MRR states that the operator or supplier must separately identify, calculate, and report all direct CO_2 emissions resulting from the combustion of biomass-derived fuels as specified in section 95115 for facilities, and sections 95121-95122 for suppliers. Biomass-derived fuel emissions must be identified by the source of fuel, as described in section 95852.2 of the cap-and-trade regulation. A biomass derived fuel not listed in that section will be required to hold a compliance obligation under section 95852.1. For a fuel listed under section 95852.2, reporting entities must also meet the verification requirements in section 95131(i) of this article, or the fuel must be identified as an Other Biomass-Derived Fuel and be subject to a compliance obligation under section 95852.1. By not including biomass-derived fuels under the cap, we are recognizing that the use of a biomass-derived fuel is preferred over the use of fossil fuels at capped sources for the purposes of achieving the AB 32 emissions target.
>
> The scope of this regulation is to apply a compliance obligation on direct emissions from capped entities. Any lifecycle analysis of biomass-derived fuel and its potential emissions or impacts beyond the emissions at the capped entities is not within the scope of this regulation. The program will include transportation fuels under the cap starting in 2015. Therefore, GHG emissions associated with the transport of biomass material will be covered under the cap. We are developing an adaptive management plan to monitor and adjust the program for any unanticipated adverse impacts to stocks of woody biomass as a result of offset projects. We do not believe that exempting emissions from combustion of woody biomass will result in the harmful removal of woody biomass from forests as there are existing environmental protection laws that serve to protect against the denuding of the forests. The data collected under the MRR will help ARB monitor increases in biomass-derived fuels, types of specific fuels, and source location to monitor for any changes to the use of biomass-derived fuels as a potential result of this program. The reporting requirements in the MRR have been subject to a public review and comment process as part of that rulemaking.

E-21. Comment: LADWP supports the use of biomass-derived fuels for meeting compliance with the 33 percent RES as they play a critical role in the ability of utilities to meet the standard at the lowest cost. Use of digester gas or other biogas that is upgraded to pipeline quality, in lieu of natural gas to generate electricity, is a beneficial use of waste gas and should be encouraged and supported by ARB. LADWP recommends that ARB recognize the displacement of fossil fuels and treat biomass-derived fuels that are RES-compliant as having zero GHG emissions compliance obligation under the cap-and-trade program when used in the generation of electricity. LADWP recommends that ARB reassess how it addresses contract shuffling to make sure that it does not hinder the beneficial displacement of fossil fuels for generating electricity.

The cross reference to the MRR in section 95131(i)(2)(A)(2) unnecessarily restricts biomass-derived fuel to contracts in effect prior to January 1, 2010 and that remain in effect; or fuel provided under a contract dated after January 1, 2010 only for the amount of fuel that is associated with an increase in the biomass-based fuel producer's capacity. The MRR ISOR indicates that this provision is to prevent contract shuffling. Undue restrictions to address contract shuffling will result in increased costs for compliance with the RES regulation and the cap and trade regulation. (LADWP1)

> **Response:** We agree that the use of biogas to generate electricity is beneficial, but we believe that the regulation must prevent leakage by ensuring that biogas is not merely redirected to California while being replaced with fossil fuel outside of California. The second paragraph addresses primarily the MRR, not this regulation. But the text in that section of the MRR was subsequently moved to this regulation. New section 95852.1.1 makes it clear that emissions from biogas and biomethane under contract prior to January 1, 2012, do not have a compliance obligation. This new section also clarifies that there is no compliance obligation for emissions from these fuels provided under contracts dated after January 1, 2012, if the contracts are for fuel associated with an increase in the producer's capacity, or new production, or recovery of fuel that was previously destroyed. This provision for new contracts is necessary to prevent leakage.

E-22. Comment: In order to ensure the program is of reasonable size and scope, and doesn't create a costly disincentive to utilize biomass overall, CARB should consider easing the reporting and tracking requirements for certain sources of bioenergy where there is clarity on atmospheric carbon flux values. In such circumstances, CARB could allow landowners or biomass users to certify the source of their bioenergy and utilize lookup tables with default emissions factors and carbon flux values. (KUSTIN06)

> **Response:** We believe the current reporting and verification requirements in the MRR for biomass-derived fuels strike a good balance between cost-effectiveness and credible reporting to support the cap-and-trade program. The same level of accounting is necessary for emissions with a compliance obligation and those that are exempt, to ensure the environmental integrity of the cap-and-trade program.

E-23. Comment: California's proposed Cap and Trade program should recognize the carbon neutrality of biomass. The only reasonable option for treatment of emissions from biomass-derived fuels is to exempt them from having a compliance obligation. We believe the agency's approach to combustion emissions from ethanol and other biomass-derived fuels outlined in section 95852.2 of the proposed regulation is appropriate and scientifically justified. The approach of exempting emissions from biomass-derived energy from counting toward a covered entity's compliance obligation is consistent with the treatment of biomass emissions in other established regulatory frameworks, policy proposals, and accounting protocols. We encourage CARB to resist requests to require a compliance obligation for emissions from bioenergy, as well as any other appeals to otherwise include bioenergy emissions under the cap. CARB should continue to avoid attempting to capture emissions from changes in carbon stocks due to land use changes under the cap, since those emissions are outside the scope of the cap and trade program. Further, speculative emissions related to land use change are already being dealt with separately through the LCFS (although there is significant controversy and disagreement surrounding the methods used by CARB to estimate such emissions). Potential changes in land-based carbon stocks should not obfuscate or interfere with the carbon neutrality of biomass under the cap and trade program. Indeed, land use change emissions and the biomass carbon cycle are two distinctly separate issues and should continue to be treated as such. (RFA)

Comment: A letter to Chairman Mary Nichols and members of the board by a group of environmental organizations on December 9, 2010, urges the Board to, in effect, remove section 95852.2 from the proposed regulation. Their rationale for requesting this adjustment to the proposed regulation is thoroughly flawed, and the adjustment they request should be rejected.

The letter argues that the adjustments they are requesting are consistent with the approach taken by US EPA. This is simply not correct. The latest EPA Guidance on Greenhouse Gas Permitting recommends that permitting authorities continue to treat biomass as carbon-neutral while it determines whether to exclude some designated forms of biomass from the carbon neutral category.

The letter asserts that the rule assumes carbon neutrality for all biomass fuels. This is incorrect. The rule in section 95852.2 lists the specific categories of biomass that can be used for energy production without incurring a compliance obligation. All of the biomass materials listed in the rule have been shown to have reduced greenhouse gas emissions when used for energy production, rather than meeting an alternative fate such as landfill disposal, open burning, and enhanced risk of destructive wildfires for the state's forests.

The letter does admit that in some instances the use of biomass to make energy will result in de minimus or net carbon negative emissions. In fact, of the fuel that is used by the California biomass industry, all of it results in de minimus or net carbon negative emissions. The positive greenhouse-gas performance of the industry has been well documented.

The principal concern expressed in the letter concerns the use of fuels derived from forest biomass. Indeed, in presenting an example of a biomass fuel category that could cause an increase in the atmospheric burden of greenhouse gases, the letter cites: "conversion of standing forests to bioenergy without forest replacement." In fact, that category of biomass fuel has a compliance obligation in section 95852.2 of the rule and, therefore, would be subject to regulation without any modification of the rule. Section 95852.2 (a) (4) requires that forest-derived fuels be harvested according to the State forestry practices act, and be harvested specifically for purposes of fire risk reduction or other forest improvement goals.

The letter implies that the greenhouse gas implications of using forest derived fuels have not been sufficiently studied to justify exempting fuels consistent with section 95852.2 (a) (4) from a compliance obligation. In fact, in addition to the Pacific Institute report, which analyzed the issues, the U.S. Forest Service performed a comprehensive life-cycle analysis of the greenhouse gas implications of forest fuels use over a defined landscape in Northern California for the CEC's PIER program. Both studies demonstrate that the use of forest fuels that are consistent with section 95852.2 (a) (4) of the rule will reduce the burden of greenhouse gases in the atmosphere over the long term, fully consistent with AB 32.

California today has 33 biomass electric generating facilities, distributed across 19 counties, with a combined generating capacity of over 600 MW of reliable, baseload, renewable power that can be counted on and scheduled. Biomass power is approximately two percent of the overall power generated in the State, and about 18 percent of all the renewable power generated in the State. The industry employs approximately 750 workers directly at the power plants, and supports approximately 1,500 additional jobs in fuels production and transportation. Most of these jobs are in rural areas of the State. These are some of the "green jobs" promised by the State's moves to reduce greenhouse gas emissions. Biomass power production in California is a critical component of the State's renewable energy needs, solid-waste disposal infrastructure, and air quality improvement goals. (CBEA1)

Response: Thank you for the support.

E-24. Comment: Treatment of biofuels and biomass should be consistent for the transportation, electricity, and industrial sectors. ARB’s Cap and Trade should reward only biofuels that have lower GHG emissions than conventional fuels. (EDF1)

Response: We believe the regulation promotes these objectives.

E-25. (multiple comments)
Comment: EDF encourages the inclusion of biomass combustion to generate bioenergy in the cap starting in 2015. (CEERT, EDF1, EDF2)

Comment: We urge CARB to fully account for emissions from biofuel combustion in the cap and trade program starting in Phase II (year 2015) with adjustments or other mechanisms to account on a performance basis for both the combustion emissions and the landscape carbon effects associated with waste utilization and biomass production and harvest. (EDF1)

> **Response:** We will continue to evaluate this proposal as part of future amendments to the rule.

E-26. (multiple comments)
Comment: Combustion emissions from biogas resources should be properly accounted for. Section 95852.2 describes emissions for which there is no compliance obligation. These are generally emissions from combustion of biogenic fuels, which are reasonably excluded from a compliance obligation because their combustion offsets fossil fuel combustion while also eventually or even simultaneously reducing the release of methane gas to the atmosphere. However, this section inexplicably appears to exclude biogas from digesters from this reasonable treatment. The regulation should clearly exempt all eligible biomass and biogas combustion from a compliance obligation. (SMUD1)

Comment: Since ARB has imposed a quantitative limit on the number of offsets (lowering their value relative to an allowance), being required to surrender allowances from combustion emissions and receiving additional upstream offsets are not equivalent. In this circumstance, receiving a compliance obligation and earning fewer upstream offsets would be a better alternative. American Biogas Council does not advocate an approach whereby fewer offsets are awarded. Bio-methane economics often require revenue streams from both offsets as well as the ability to sell the biogas. Reducing the number of offsets received would limit the number of projects undertaken, further inhibiting offset supply and preventing meaningful GHG reductions from taking place. However, this approach is the preferred alternative to requiring compliance obligations for combusting biogas. (ABC)

> **Response:** We have made clarifications to address this concern. Combustion emissions from a digester are exempt from a compliance obligation as long as any credits for methane destruction from the digester do not receive more credit than calculated using the Global Warming Potential from the IPCC, Second Assessment.

Geothermal

E-27. (multiple comments)
Comment: We ask that ARB consider clarifying in sections 95852 and 95852.2 that emissions from geothermal facilities do not have a compliance obligation. We believe the following proposed amendments by the geothermal industry in California merely clarifies ARB's existing intent while not creating any additional confusion about what is a "fugitive" versus "process" emissions. Modify sections 95852(h) and 95852.2(f) and (g) as follows:

(h) The compliance obligation is calculated based on the sum of [(i)-(iv) unchanged]; and (v) all process and vented emissions of CO_2, CH_4, and N_2O as specified in the Mandatory Reporting Rule except for those listed in section 958522(g) below.

Modify section 95852.2. as follows:

(f) Emissions from geothermal generating units and geothermal facilities;
(g) Fugitive and process emissions from:

(1) CO_2 emissions from hydrogen fuel cells;
(2) At petroleum refineries; asphalt blowing operations, equipment leaks, storage tanks and loading operations; or
(3) At the facility types listed in section 95101(e) of the Mandatory Reporting Regulation, Petroleum and Natural Gas Systems; leak detection and leaker emission factors, and stationary fugitive and "stationary vented" sources on offshore oil platforms. (ORMAT)

Comment: The proposed regulation needs to be revised to clarify that GHG emissions resulting from geothermal power sources are not subject to a compliance obligation. California is fortunate to have some of the largest geothermal reservoirs in the world. Unlike intermittent renewable generating sources, such as wind and solar, geothermal power represents a continuous, baseload supply of clean energy, without requiring any combustion of fossil fuels. As such, geothermal resources represent a significant and important component of California's renewable generating portfolio. However, GHG emissions from geothermal power plants can, in most cases, reasonably pass through a stack, vent or other functionally equivalent opening. Acknowledging this fact, the proposed revisions to the MRR would no longer categorize emissions from geothermal generating sources as "fugitive" in nature. See 17 CCCR 95112(f) (proposed) ("Operators of geothermal generating facilities must calculate annual emissions of CO_2 and CH_4 from geothermal energy sources using source specific emission factors derived from a measurement plan approved by ARB"). In light of these changes to the MRR and in recognition of the fact that GHG emissions from geothermal generating sources are not truly fugitive in nature, Calpine would recommend that CARB revise the proposed regulation so that the exemption for GHG emissions associated with geothermal power generation no longer depends upon their classification as either "fugitive emissions" or "process emissions," but is instead separately enumerated within the proposed regulation. Modify sections 95852(h) and 95852.2(f) as follows:

> (h) The compliance obligation is calculated based on the sum of (i) emissions of CO_2, CH_4, and N_2O resulted from combustion of fossil fuel; (ii) emissions of CH_4 and N_2O resulted from combustion of all biomass-based fuel; (iii) emissions of CO_2 resulted from combustion of unverifiable biomass-derived fuels, as specified in section 95852.2; (iv) emissions of CO_2 resulted from combustion of biomass-derived fuels not listed in section 95852.2; and (v) all process and vented emissions of CO_2, CH_4, and N_2O as specified in the Mandatory Reporting Rule except for those listed in section 95852.2(~~a)(6~~g) below.

(f) ~~Fugitive and process emissions from: (1) CO_2 emissions from~~ Geothermal generating units~~; (2) CO_2~~ and ~~CH_4 emissions from~~ geothermal facilities~~;~~

(~~3~~g) Fugitive and process emissions from:

(1) CO_2 emissions from hydrogen fuel cells;

(~~4~~2) At petroleum refineries: asphalt blowing operations, equipment leaks, storage tanks, and loading operations; or

(~~5~~3) At the facility types listed in section 95101(e) of the Mandatory Reporting Regulation, Petroleum and Natural Gas Systems: leak detection and leaker emission factors, and stationary fugitive and "stationary vented" sources on offshore oil platforms. (CALPINE1, CALPINE2)

Comment: The geothermal energy industry is a leading provider of renewable energy in California, and reported data from California's geothermal facilities has clearly demonstrated that any GHG emissions associated with the generation of this electricity is de minimus. NCPA recommends proposed revisions to section 95852 (Emissions Categories Used to Calculate Compliance Obligations) and section 95852.2 (Emissions without a Compliance Obligation) that would clarify the intent of the proposed regulation that emissions from geothermal generation not be subject to a compliance obligation in the Program. Modify sections 95852(h) and (v) and 95852.2(f) and (g) as follows:

(h) The compliance obligation is calculated based on the sum… and
(v) all process and vented emissions of CO_2, CH_4, and N_2O as specified in the Mandatory Reporting Rule except for those listed in section 95852.2(a)(6)(g) below.

(f) Emissions from geothermal generating units and geothermal facilities, ~~Fugitive and process emissions from:~~
(g) Fugitive and process emissions from:

~~(1) CO_2 emissions from geothermal generating units;~~

~~(2) CO_2 and CH_4 emissions from geothermal facilities;~~

(1) CO_2 emissions from hydrogen fuel cells;

(2) At petroleum refineries: asphalt blowing operations, equipment leaks, storage tanks, and loading operations; or

(3) At the facility types listed in section 95101(e) of the Mandatory Reporting Regulation, Petroleum and Natural Gas Systems: leak detection and leaker emission factors, and stationary fugitive and "stationary vented" sources on offshore oil platforms. (NCPA1)

Comment: CARB has chosen to characterize geothermal facility GHG emissions as either "fugitive" or "process" emissions for mandatory reporting purposes. These terms are essentially a proxy category for the types of GHG emissions that can be measured at geothermal facilities but are not completely accurate given that naturally occurring GHG emissions from geothermal facilities can pass through cooling stacks. Given the factors mentioned above, and given that the proposed regulation does not propose a compliance obligation for geothermal facilities, we would ask that ARB consider the following amendment to sections 95852 and 95852.2 to clarify that emissions from geothermal facilities do not have a compliance obligation. We believe that GEA's proposed amendment merely clarifies ARB's existing intent, while not creating any additional confusion about what is a "fugitive" versus "process" emission. Modify sections 95852(v) and 95852.2(f) and (g) as follows:

(v) all process and vented emissions of CO_2, CH_4, and N_2O as specified in the Mandatory Reporting Rule except for those listed in section 95852.2(g)

(f) Emissions from geothermal generating units and geothermal facilities.
(g) Fugitive and process emissions from:

(1) CO_2 emissions from hydrogen fuel cells;
(2) At petroleum refineries: asphalt blowing operations, equipment leaks, storage tanks, and loading operations; or
(3) At the facility types listed in section 95101(e) of the Mandatory Reporting Regulation, Petroleum and Natural Gas Systems: leak detection and leaker emission factors, and stationary fugitive and "stationary vented" sources on offshore oil platforms. (GEA)

Comment: CalEnergy requests that ARB clarify in sections 95852 and 95852.2 that greenhouse gas emissions from geothermal facilities do not have a compliance obligation under the cap and trade program by adding a new section under section 95852.2 to specifically address emissions from geothermal generating units and facilities (designed as subparagraph (f)), and separating out exempt fugitive and process emissions. Modify sections 95852(h) and 95852.2(f) and (g) as follows:

(h) The compliance obligation is calculated based on the sum of

(i) emissions of CO_2, CH_4 and N_2O result~~ed~~ing from the combustion of fossil fuel;
(ii) emissions of CH_4 and N_2O result~~ed~~ing from combustion of all biomass-based fuel;
(iii) emissions of CO_2 result~~ed~~ing from combustion of unverifiable biomass-derived fuels, as specified in section 95852.2;
(iv) emissions of CO_2 result~~ed~~ing from combustion of biomass-derived fuels not listed in section 95852.2; and
(v) all process and vented emissions of CO_2, CH_4, and N_2O as specified in the Mandatory Reporting Rule except for those emissions from sources listed in section 95852.2~~(a)(6)~~(g) below.

(f) all greenhouse gas emissions from geothermal generating units and geothermal facilities.
~~(f)~~(g) Fugitive and process emissions from:

~~(1) CO2 emissions from geothermal generating units;~~
~~(2) CO2 and CH4 emissions from geothernal facilities;~~
~~(3)~~(1) CO_2 emissions from hydrogen fuel cells;

~~(4)~~<u>(2)</u> At petroleum refineries: asphalt blowing operations, equipment leaks, storage tanks, and loading operations; or
~~(5)~~<u>(3)</u> At the facility types listed in section 9510l(e) of the Mandatory Reporting Regulation, Petroleum and Natural Gas Systems; leak detection and leaker emission factors, and stationary fugitive and "stationary vented" sources on offshore oil platforms. (CALENERGY)

Response: We agree and modified section 95852.2(b) to clarify that emissions from geothermal generating units and geothermal facilities do not hold a compliance obligation. Based on stakeholder comments, staff concluded that although geothermal facilities must report under the Mandatory Reporting Regulation, they will not hold a compliance obligation. ARB will monitor their activities via the CEC Renewables Portfolio Standards program. We also fixed the reference previously in item (v) of section 95852(h).

E-28. Comment: Include a process to add to the list of fuels without a compliance obligation. Modify section 95852.2 as follows:

Emissions from the following source categories as identified in sections 95100 through 95199 of the Mandatory Reporting Regulation count toward applicable reporting thresholds but does not count toward a covered entity's compliance obligation set forth in this regulation. <u>The Executive Officer may add additional source categories meeting similar criteria</u>. These source categories include Municipal Solid Waste. (CCEEB1)

Response: Combustion emissions from the biomass derived portion of biomass derived fuels such as municipal solid waste count toward applicable reporting thresholds but do not count toward a covered entity's compliance obligation unless those emissions are reported as other biomass CO_2 under MRR. Additional changes to this requirement will be considered in any future amendments to the MRR and cap-and-trade regulation. The Municipal Solid Waste sector is not excluded from this program.

E-29. Comment: List biofuel plants as a covered stationary source. The proposed regulation includes a list of specific industrial processes (e.g. petroleum refining) in the definition of entities covered by the emission cap (see section 95811). This list does not specifically include biofuel production facilities but appears to capture such facilities under the more general category of "stationary combustion." All transportation fuels must be treated equitably within the regulatory framework. While it is appropriate that CO_2 emissions from the combustion of biofuels are not included under the state emission cap, fossil carbon emissions from stationary source production of biofuels should be included in the cap if individual biofuel production facilities exceed the 25,000 TPY emission threshold. CARB should clarify that biofuel plants with emissions greater than 25,000 TPY qualify as covered sources by specifically including them in the list of covered facilities in section 95811. (CONOCO)

Response: Only biomass-derived fuels as listed in section 95852.2, Emissions without a Compliance Obligation, are exempt from holding a compliance obligation. Those that are not verified as meeting the requirements in this section will be reported as other biomass CO_2 and will hold a compliance obligation. We believe the regulation is written to include biofuel plants if they meet the applicability threshold of 25,000 metric tons of CO_2e per year.

E-30. Comment: We wish to compliment ARB on your treatment of biomass under section 95852 of the proposed Cap and Trade regulation. Section 95852.2 provides a well-reasoned listing of biomass sources that have been shown to have lower emissions levels of greenhouse gases when used for energy production than when disposed of using conventional means, such as landfill disposal and open burning. We urge the ARB board to implement the Cap and Trade rules without modification of the sections pertinent to biomass energy production and protect this important green jobs industry. (CBEA1, CBEA2)

Response: Thank you for the support.

E-31. Comment: Neither a justification, nor an evaluation of impacts was provided, nor could we imagine any possible justification for the exemptions section 95852.2 (c)(1), (2), and (3) and (f)(4) and (5). Exemptions, such as this, are entirely inconsistent with requirements for maximizing reductions and should be struck. (CBE1)

Response: Combustion emissions from the biomass-derived portion of fuel ethanol do not hold a compliance obligation. However, emissions that are not verified as being biomass-derived will be reported as other biomass, and will hold a compliance obligation. Fugitive and process emissions from asphalt blowing operations, equipment leaks, storage tanks, and loading operations at petroleum refineries; or leak detection and leaker emission factors, and stationary fugitive and “stationary vented” sources on offshore oil platforms do not hold a compliance obligation. One important criterion for inclusion under the cap is an accurate quantification methodology for emissions sources. We don’t believe we have sufficient methods to accurately quantify these types of emissions for inclusion under the cap and apply a carbon cost. We will continue to evaluate new information and technology related to the quantification of these emissions.

E-32. Comment: Section 95852.2 (p. A-64) identifies emissions that do not trigger a compliance obligation. The section contains some problematic provisions. The opening sentence refers to “Emissions” without qualification, although it appears from section 95852(h) (p. A-63) that only CO_2 emissions from combustion of biomass-derived fuel are exempt. CH_4 and N_2O emissions will carry liability. (SCPPA1)

Response: We modified this section. The compliance obligation for covered sources is calculated based on the sum of emissions of CO_2, CH_4, and N_2O that resulted from combustion of fossil fuel; emissions of CH_4 and N_2O that resulted from combustion of all biomass-derived fuel; emissions of CO_2 that resulted from combustion of biomass-derived fuels that do not meet the requirements in section 95852.2 (Emissions without a Compliance Obligation); emissions of CO_2 that resulted from combustion of biomass-derived fuels pursuant to section 95852.1; and all process and vented emissions of CO_2, CH_4, and N_2O as specified in the MRR, except for those listed in section 95852.2(b), Fugitive and Process Emissions. Finally, CH_4 and N_2O are covered greenhouse gases under this regulation.

E-33. Comment: In section 95852.2(a) there is a reference to combustion emissions from biomass-derived fuels, but in subsections (b), (c), (e), and (f) there is no reference to combustion of the fuels. SCPPA understands from discussions with ARB staff that this was an unintended consequence of a formatting error and that subsections (b), (c), (e), and (f) should instead be subsections (5) to (8) in section 95852.2(a). (SCPPA1)

Response: We corrected the formatting error in section 95852.2.

E-34. (multiple comments)
Comment: Section 95852.2(a) inappropriately excludes emissions from “biogas from digesters” from the category of emissions that do not trigger a compliance obligation. It appears that biogas from digesters is excluded from being considered zero-CO_2-emissions because such gas may be from projects that earn offsets under ARB’s Compliance Offset Protocol for Livestock Manure (Digester) Projects (Protocol). However, the protocol only applies to livestock manure digester projects. Digester gas can be collected from other sources that would not be covered by this Protocol. More importantly, the protocol awards offsets for avoiding methane emissions from livestock manure, not for avoiding fossil fuel emissions. The protocol (p. 6) makes a clear distinction between the two types of emission reductions. This protocol does not account for carbon dioxide emission reductions associated with displacing grid-delivered electricity or fossil fuel use. The staff report for the protocol echoes this (on page 6 of the report). (SCPPA1, SCPPA5, SMUD2)

Comment: The use of biogas for producing power for the electricity grid or electricity for on-site use, thereby displacing fossil-fueled power plant GHG emissions, is considered a complementary and separate GHG project activity and is not included within the offset protocol accounting framework.

Insofar as the emission reductions from displacing fossil fuel with biogas are not covered by the protocol, no offsets are awarded under the protocol for those emission reductions. Offsets are only awarded for avoiding methane emissions. The Cap and Trade regulation should recognize emission reductions from displacing fossil fuel with biogas by allowing biogas combustion to be treated as zero-CO_2-emissions, regardless of whether offsets have been, or could be, issued for avoiding methane emissions. Modify section 95852.2 as follows:

<u>CO_2</u> ~~E~~<u>e</u>missions from the following source categories as identified in sections 95100 through 951<u>58</u>~~99~~ of the Mandatory Reporting Regulation …

(a) Combustion emissions from biomass-derived fuels ~~(except biogas from digesters)~~ from the following sources: …

(~~e~~8) Biogas~~methane~~ from the following sources:

(A~~1~~) All animal and other organic waste; or
(B~~2~~) Landfill, ~~gas and~~ wastewater, and digester gas. (SCPPA1)

Comment: PG&E recommends that ARB clarify the treatment of biogas and biomass as described in section 95852.2(a) exempts combustion emissions from biomass-derived fuels from a covered entity's compliance obligation, except for biogas from digesters, while section 95852.2(e) exempts biomethane from all animal and other organic waste, landfill gas and wastewater. This section therefore appears to state that if biogas from digesters were combusted, those emissions would not be exempt, but if biomethane were released into the atmosphere, those emissions would be exempt. Modify section 95852.2(e) as follows:

(e) Combustion and fugitive ~~B~~biomethane emissions from the following sources: (PGE1).

Response: We agree and revised the regulation accordingly.

E-35. (multiple comments)
Comment: Modify section 95852.2 to include the following source categories:
(e) Biomethane or biogas from the following sources:
(2) Landfillgas and wastewater treatment plants
(f)(6) CH_4 from landfills.
(f)(7) CH4 and N_2O from POTWs. (LASD1)

Comment: We are greatly concerned that the language proposed in the draft is confusing and not consistent with staff's intent to exclude emissions of biogas, including digester gas from wastewater treatment, from compliance obligations. Modify section 95852.2 as follows:

(a) Combustion emissions from biomass-derived fuels (except biogas from digesters) from the following sources:
(e) Biomethane and biogas from the following sources:
(1) All animal and other organic waste; or
(2) Landfills gas and wastewater treatment.
(f) Fugitive and process emissions from:
(1) CO_2 emissions from geothermal generating units;
(2) CO_2 and CH_4 emissions from geothermal facilities;
(3) CO_2 emissions from hydrogen fuel cells;
(4) At petroleum refineries: asphalt blowing operations, equipment leaks, storage tanks, and loading operations;

(5) At the facility types listed in section 95101(e) of the Mandatory Reporting Regulation, Petroleum and Natural Gas Systems: leak detection and leaker emission factors, and stationary fugitive and “stationary vented” sources on offshore oil platforms; or
<u>(6) Methane from landfills.</u>
<u>(7) Methane and N_2O from municipal wastewater treatment plants.</u>
(BACWAAC)

Response: We agree and modified this section.

E-36. (multiple comments)
Comment: It is critical to potential wastewater credit generation that the wording "except biogas from digesters" is removed from section 95852.2. We believe this was unintended and only confuses this subsection with manure digesters. The wastewater industry in California has many digesters that would be very negatively impacted by this provision. (LASD1)

Comment: I understand that the phrase "(except biogas from digesters)" in the first line of 95852.2(a) is meant to exclude offset credits, and not biogas or biomethane in general. It would be very helpful that this change keeps clear that it is not meant to exclude biomethane as provided in 95852.2(e)/(a)(8). (WEINSTEIN)

Response: We agree and removed this term from section 95852.2(a).

Wastewater

E-37. Comment: Biogas emissions from digesters should not hold a compliance obligation, (page A-64 subparagraph (a)). Subparagraph (a) indicates emissions from biomass-derived fuels (except biogas from digesters) count toward applicable reporting thresholds, but do not count toward a covered entity's compliance obligation. The exclusion of digester biogas from this provision suggests that it is counted toward a covered entity's compliance obligation. This appears to be inconsistent with subparagraph (e) on page A-66 that indicates biomethane from all animal and other organic waste, or landfill gas and wastewater are categories without a compliance obligation under the cap and trade program. Subarticle 3 (Applicability) correctly does not include publicly owned treatment works (POTW) or sewage treatment plants as a category of covered entities. However, it appears that if that digester gas, whether from municipal sewage or livestock, is captured and flared it does not create a surrender obligation. If that same digester gas is combusted to generate electricity instead of being flared, the same gas will have GHG emissions that would then count toward an allowance surrender obligation for a covered entity, such as an electric utility. (LADWP1)

Response: We modified section 95852.2(a) to exempt the following from a compliance obligation: combustion emissions from biomethane; biogas from all animal and other organic waste or landfill and wastewater treatment plants; and fugitive, process, and vented emissions from CH_4 and N_2O from municipal wastewater treatment plants.

E-38. (multiple comments)
Comment: We believe that local government agencies such as wastewater treatment facilities should be exempted from compliance obligations under the cap and trade program. (BACWAAC, CAWWCCG1)

Comment: We suggest that following adoption of this regulation, ARB direct staff to continue to work with local government stakeholders including the wastewater treatment community regarding full exemption from the regulation. While wastewater facilities currently fall under the compliance threshold due to the exclusion of biomass emissions (assuming the changes recommended above are made), we are concerned that changes to plant operations, calculation methodologies, covered sectors under EPA's mandatory reporting rule (which ARB is aligning with in its mandatory reporting rule), thresholds, or other unforeseen conditions have the potential to bring wastewater treatment agencies into the cap in the future. Rather than waiting for these changes to occur, we request that staff continue to work with us to consider solutions including an exemption. Wastewater treatment is a necessary service, and emissions associated with wastewater would happen whether or not our facilities are present. We cannot control the quantity or quality of our inflow nor the water quality requirements placed on our effluent, which drive the treatment methods selected. Therefore, we cannot control our emissions, and because we cannot move, we do not present any leakage risk. As public agencies, we have very specific procurement rules and lengthy budgeting processes, and we cannot adapt to market conditions sufficiently to ensure compliance at a reasonable cost in a market-based system. Finally, we cannot pass compliance costs on to customers due to the public processes associated with our rate-setting. For these reasons, we believe an exemption from compliance obligations is appropriate and we would like to continue to work with staff toward this end. (EMWD, ACWA, BACWAAC, CAWWCCG1)

Comment: We urge the Board to direct staff to work with the wastewater community to consider an exemption from the cap for wastewater facilities. Similar to the Marines plea, we think we're different. And though our mission is different, we think enabling you all to flush every day is a pretty critical activity as well. So our agencies can't control what comes into our facilities or the effluent requirements we need to meet, and those drive our emissions. So we request that you consider working with us going forward to consider an exemption. (CAWWCCG2)

> **Response:** We modified section 95852.2(a) to exempt the following from a compliance obligation: combustion emissions from biomethane; biogas from all animal and other organic waste or landfill and wastewater treatment plants; and fugitive, process, and vented emissions from CH_4 and N_2O from municipal wastewater treatment plants.

If in the future, any covered sources at these facilities trigger the threshold for a compliance obligation, we will evaluate the concerns related to cost pass through.

E-39. (multiple comments)
Comment: WIRA supports the staff position that GHG emissions associated with biodiesel not be subject to an allowance obligation. This policy will continue to promote the development of non-fossil fuel based alternative fuels. (WIRA1, PMTPETRO1)

Comment: We strongly support the changes to the language regarding emissions without a compliance obligation that are presented in Attachment B to today's resolution. These changes clarify staff's intent to exclude biogas emissions from cap and trade. And we support that as a way to beneficially use a digester gas that's produced around the state. (CAWWCCG2)

Comment: ATA supports the consistent treatment of biomass-derived fuels under the regulation with a reporting requirement, but no compliance obligation. This approach makes sense from both the perspective of encouraging development of alternative fuels and the perspective of addressing biomass-derived fuel emissions consistently across all sources. (ATAA)

Comment: We support modifications to the language in section 95852.2 that clarify staff's intent with respect to biomass sources without a compliance obligation. (EMWD, ACWA, CAWWCCG1)

Response: Thank you for the support.

E-40. Comment: Fugitive and vented emissions from natural gas systems are already being captured under the compliance obligation of Natural Gas Suppliers, since these entities will report using an “upstream approach,” meaning that the compliance obligation will be based on the volume of gas received at the State border or city gate minus volume of gas delivered to storage or entities directly regulated. Therefore, fugitives and vented emissions should be exempt from a direct cap and trade compliance obligation (in section 95852.2(f)) because they are already being captured under the compliance obligation of Natural Gas Suppliers. Because of the imprecise methodologies used in calculating natural gas system fugitive and vented emissions, and because these emissions are already being captured under the compliance obligation of Natural Gas Suppliers, they should be exempt from a direct cap and trade compliance obligation. PG&E recommends that section 95811 also be revised to reflect this change. Modify section 95852.2(f)(5) as follows:

(5) ~~At t~~The facility types listed in section 95101(e) of the Mandatory Reporting Regulation, Petroleum and Natural Gas Systems.~~: leak detection and leaker emission factors, stationary fugitive and “stationary vented” sources on offshore oil platforms~~ (PGE1)

Response: We have clarified section 95858.2 to exempt vented and fugitive emissions from several types of activities associated with Petroleum and Natural Gas systems.

E-41. Comment: Section 95852(h)(v) references exemptions listed in section 95852.2(a)(6). However, that section does not exist. It is PG&E's understanding that the list of exemptions in part (v) is supposed to reference section 95852.2(f). (PGE1)

Response: We modified this section, which is now included as section 95852(i).

E-42. Comment: ATA appreciates that the regulation more clearly excludes aircraft fuel from coverage under the regulation and no longer includes a placeholder for the inclusion of additional fuels in the future. The exclusion of aircraft fuel is necessary and appropriate in light of federal preemption of State regulation in this area. (ATAA)

Response: No response necessary.

E-43. Comment: CO_2e emissions from biomass plants will not be subject to the compliance obligation if certain verifiable criteria are met. Clarify section 95131(i), which states that if the fuel is not certified by an accredited certifier of biomass-derived fuels, the verification team shall examine the fuel contracts to determine if the fuel being provided under a contract dated after January 1, 2010, is only for the amount of fuel that is associated with an increase in the biomass-based fuel producer's capacity. This seems to state that a biomass purchaser cannot purchase additional fuel from a supplier unless the supplier has increased their fuel output. It would be allowed to purchase additional fuel from a supplier if a previous purchaser is no longer purchasing biomass fuel from that supplier. (CONSTELLATIONENERGY)

Response: We modified section 95131(i) of the MRR to clarify the verification requirements of biogas and biomethane; urban, agricultural, and forest wood waste; biodiesel and fuel ethanol; municipal solid waste; and tires. These modifications will assist verifiers with the assessment of these fuels. To avoid emissions leakage, only increased or new production of biomass-derived fuels is exempt from holding a compliance obligation. The contract date has been changed from January 1, 2010, to January 1, 2011.

E-44. Comment: We ask that the Board, when you move forward with the implementation of these cap and trade regulations, continue to recognize the greenhouse gas reduction benefits associated with waste-derived energy and resources. We urge you to continue to recognize biogas and biomass derived fuels as carbon neutral, particularly those biomass and biogas fuels that are derived from waste materials. (WM2)

Response: No response necessary.

Municipal Solid Waste

E-45. (multiple comments)
Comment: Waste-to-energy facilities have no ability to control the incoming MSW, so there would be no opportunity to reduce fossil-based CO_2 emissions, leaving the purchasing of allowances, or CARB compliance obligations, as the only option. Additionally, these facilities cannot pass these allowance costs through to their customers since the customers would instead choose the cheaper option of landfilling, resulting in a greater amount of greenhouse gas emissions, as described previously; an "internal to California leakage." CCEEB believes that these waste-to-energy facilities should receive a full exclusion from compliance obligations rather than the partial exclusion outlined in section 95852.2(d). This is consistent with other widely recognized International cap and trade frameworks, proposed federal climate legislation and the regional program, RGGI, which is an important consideration for future linkage. Finally, existing state law, H&S Code section 41516 recognizes the important nature of these facilities, and "that such projects should therefore be encouraged as a matter of state policy." A huge financial burden placed on local governments to purchase allowances, with a strong potential to actually increase greenhouse gases if these facilities were forced to close down, is not consistent with this state policy. (CCEEB)

Comment: The proposed regulation imposes great hardship on existing and potential future Waste-to-Energy facilities. ARB is taking the unprecedented step of requiring that waste-to-energy facilities be subject to a GHG emissions cap. Throughout the world, these facilities are treated as sources of renewable energy rather that sources of GHG emissions. The bulk of overall GHG emissions from waste-to-energy emissions (approximately 65 percent) are from biogenic waste sources (green waste, paper, etc.) internationally recognized as being part of the "near-term" carbon cycle that are not counted as part of a GHG Cap and Trade program. The remaining approximately 35 percent of emissions are from anthropogenic (fossil) sources, but these are waste sources that would be generated in any event as a waste (i.e., non-recyclable plastics). These are waste materials that are destined for disposal and, without waste-to-energy, would require disposal in a landfill. Even so, the fossil emissions of a typical waste-to-energy plant are lower than coal or oil-fired emissions and are only slightly higher than that of a combined cycled natural gas generating facility. Avoided emissions associated with waste-to-energy facilities, including:

- Avoided fossil fuel emissions from other energy sources,
- Avoided landfill methane emissions, and
- Avoided emissions associated with recycling and recovery of ferrous and non-ferrous metals that is achieved in a waste-to-energy plant.

These are avoided emissions that are unique to waste-to-energy and that cannot be achieved by any of the other fossil fuel (or renewable energy) sources. Indeed, if an overall life-cycle assessment of the fossil fuel energy source were used to include energy production and transportation emissions, the emissions associated with the other fossil energy sources would be even higher.

WM firmly believes that it is inappropriate to include waste-to-energy under California's proposed Cap and Trade program given the significant GHG reductions achieved by waste-to-energy, at least not without full recognition of the life-cycle benefits associated with WTE operations. Regulation of stack carbon dioxide emissions as a point source ignores the energy and environmental benefits of waste-to-energy facilities that are more fully defined through a life cycle assessment. The significant savings in greenhouse gas emissions resulting from waste-to-energy is not theoretical, but proven by substantiated, peer-reviewed analysis of site-specific data.

The recognition of waste-to-energy as a GHG reduction technology is not without significant precedent. Other greenhouse gas regulatory programs, such as the European Union Emission Trading Scheme (EU-ETS), the Regional Greenhouse Gas Initiative (RGGI), and Congressional climate change legislation (sponsored by California's Congressman Waxman And Senator Boxer) under consideration should be viewed as potential models upon which to base a new California Cap and Trade program, at least with respect to waste-to-energy.

Under the EU-ETS, by far the largest mandatory GHG Cap and Trade program, waste-to-energy facilities are specifically excluded due to their ability to reduce GHG emissions from waste management (just as CARB has already recognized for mandatory commercial recycling). In fact, the European Environment Agency (EEA) attributes considerable reductions in waste management GHG emissions to increased levels of recycling and waste-to-energy.

Under RGGI, which regulates fossil fuel-fired utilities only, waste-to-energy facilities are specifically excluded because they burn municipal solid waste.

Further, the U.S. House-passed Waxman-Markey federal cap and trade bill (H.R. 2454), while capping fossil-fuel fired utilities, among other sources, specifically excludes waste-to-energy plants which burn five percent or less of supplemental fossil fuel (e.g., natural gas or fuel oil as a supplemental fuel). The U.S. Senate Environment and Public Works Committee approved the same exclusion in the Boxer-Kerry (S. 1733) bill. The House bill and the Senate Energy and Natural Resources Committee's approved American Clean Energy and Leadership Act (S. 1462) also establish a federal Renewable Portfolio Standard that recognizes waste-to-energy as a renewable energy source.

Finally, the net reductions achieved by waste-to-energy have been recognized internationally under the Clean Development Mechanism, as part of the Kyoto Protocol. Waste-to-energy projects can generate credits through the approved methodology AM0025, "Avoided emissions from organic waste through alternative waste treatment processes."

The goal of each of these programs is promotion of technologies and practices that lower the release of greenhouse gases into the atmosphere. Waste-to-energy helps to achieve that goal and therefore has been appropriately excluded from all other cap and trade regimes.

Any cap and trade program established by ARB should embrace the same goal as the international programs: to support technologies and methods that lower greenhouse gas emissions into our atmosphere. To some extent, CARB is heading in the correct direction with regard to solid waste management. ARB has recognized that the Climate Action Reserve (CAR) as a possible entity through which tradable GHG reduction credits may be generated. CAR has already adopted a GHG offset protocol for waste conversion technologies that recognizes the benefits of diverting organic waste from landfills to reduce methane emissions. Indeed, the GHG reduction credits derived by the CAR protocol for conversion technologies is based on reduced landfill emissions, very similar to what is achieved by a waste-to-energy facility. However, to evaluate waste-to-energy facilities accurately, ARB should also recognize the additional GHG reductions achievable by waste-to-energy through metals recycling and the recovery of energy resulting from this alternative to fossil sources.

California is only beginning to embrace the benefits of waste-to-energy in managing solid waste and producing renewable electricity, although three such facilities already exist in California. California's AB 939 (Sher, 1989) recognizes the benefits of these three facilities by allowing landfill waste diversion credit for these operations. Additionally, CalRecycle recently completed a solid waste GHG lifecycle analysis that documents the greatest future reductions in solid waste GHG emissions involve a framework that heavily emphasizes the recovery of energy from waste, including the increased use of waste-to-energy.

Subjecting waste-to-energy facilities to a California GHG Cap and Trade system without recognizing their overall lifecycle benefits will be inconsistent with other California integrated waste management policies and will jeopardize the continuing economic viability of these operations. Any program that places waste-to-energy under the cap would have the unintended consequence of increasing the release of greenhouse gases since communities may choose to close facilities or cease pursuing new capacity rather than pay the cost of compliance with a cap-and-trade program. The potential closure or reduced operation by these facilities could easily result in more waste being disposed of in California landfills and reduced metal recycling and recovery, effectively a form of emissions "leakage" that ARB is aggressively attempting to minimize. By recognizing the net reductions in greenhouse gases achieved by waste-to-energy and not regulating it under a cap, ARB can insure that waste-to-energy continues as a viable means to reduce landfill disposal and increase metal recycling and recovery, along with associated GHG emission reductions.

CalRecycle recently completed a comprehensive life-cycle assessment of GHG reductions associated with waste management practices, by employing a life cycle assessment. The initial conclusions of the CalRecycle life-cycle assessment is that the greatest degree of GHG reductions from the waste and recycling sector is achieved by maximizing energy recovery from waste.

WM strongly requests that waste-to-energy facilities be recognized for their avoided GHG emission benefits that are unique to this energy source, consistent with other state, regional, national and international programs for the reduction of GHG emissions. Rather than include waste-to-energy in the proposed cap and trade regulations based solely on the fossil fraction of the waste-derived fuel WM recommends that ARB simply recognize the additional GHG reduction benefits associated with waste-to-energy by allowing waste-to-energy plants to be evaluated on a life-cycle basis rather than purely on fossil-based emissions. (WM1)

Comment: There are three waste-to-energy facilities plants in California. We urge the Board to take a look at a broader view of waste to energy and the multiple benefits, life-cycle benefits that waste to energy provides by diverting waste from landfills, providing additional metal recovery, and providing a useful energy source. Not only can the three facilitates continue to operate, but future waste-to-energy facilitates can hopefully go forward. (WM2)

Comment: CARB is proposing only a partial exclusion of waste-to-energy from compliance obligations of the cap and trade program based upon their biogenic portion of the waste stream. The fossil- based components of municipal solid waste (MSW), such as plastics, is treated very differently. It is this fossil-based portion of the waste stream that ultimately causes the CO_2 threshold to be triggered placing waste-to-energy facilities into the proposed program. We believe this conclusion is inappropriate for the following reasons: 1) U.S. EPA, under its Mandatory Greenhouse Gas Reporting Program, has recently changed the definition of "fossil fuel" by eliminating the language, "consumer products that are derived from such materials and are combusted." EPA did not intend to indicate that MSW combustion was not a renewable energy, taken as a whole. 2) Consumer products that were originally derived from fossil materials and cannot be further recycled should not be considered a traditional, discretionary fossil fuel. They are waste products that must be managed. The primary purpose of waste-to-energy facilities is the management of MSW. They should not be treated as traditional fossil fuel-fired electricity generators who can pick and choose their fuel supply. 3) Components of post-recycled MSW, such as contaminated plastics, do not currently have recycle markets and must be managed either in a waste-to-energy facility or landfill. Life cycle analyses, using methods developed by EPA and approved by CARB, demonstrate that if one counts the avoided methane from not landfilling this waste, the anthropogenic CO_2 generated from the waste-to-energy facilities that now count towards the cap and trade threshold would instead become negative (i.e., there would be a net greenhouse gas benefit). We believe CARB should fully exclude waste-to-energy facilities from any compliance obligations under the proposed program recognizing three factors:

- Not doing so will have a severe financial impact on the facilities and the local governments they serve, potentially forcing them to shut down and making them stranded infrastructure, unable to continue because of their inability to meet their bond payments;

- It has been shown, and verified by CARB, that operating these facilities avoids methane emissions at the local landfill, resulting in a net benefit (reduction) in greenhouse gases; and
- State law clearly states that these renewable energy facilities should be encouraged "as a matter of state policy." (LASD1, LASD2)

Comment: During the 1980's when three waste-to-energy facilities were built and operated in California, several state laws were enacted to support these facilities, the most important of which is contained in section 41516 of the Health and Safety Code. We believe that CARB's proposal is not consistent with this provision of state law and the intent of the Legislature to encourage operation of these three waste-to-energy facilities. Specifically, inclusion in the cap-and-trade program could cause the shutdown of these facilities causing greater amounts of greenhouse gas emissions in California given the likelihood that the waste stream would instead be discarded in landfills. We see no logic in this endpoint and, in fact, no other cap-and-trade program in the United States or the world includes waste-to-energy facilities. (LASD1, LASD2)

Comment: We believe that CARB's proposal is not consistent with this state law and the intent of the Legislature to encourage operation of these three waste-to-energy facilities. Namely, inclusion in the cap-and-trade rule could cause the shutdown of these facilities, which would have the opposite of the intended result by creating greater amounts of greenhouse gas emissions in California due to the fact that the waste would likely have to be disposed of via landfills. In fact, no other cap-and-trade program in the United States, or internationally, includes waste-to-energy facilities in a cap and trade program. State law clearly states that these renewable energy facilities should be encouraged "as a matter of state policy." (CREA)

Comment: Severe inequity of including renewable energy facilities and in particular the Commerce Refuse-to-Energy Facility (CREF), in CARB's cap and trade program could force these waste-to-energy facilities to shut down. We are requesting that these facilities be treated like the electric, gas and oil utilities, as well as other industries in the program, and receive free allowances. Not doing so places a severe financial burden on these facilities and the local governments under which they operate. Under the current CARB cap and trade proposal, waste-to-energy facilities will not enjoy the benefits of free allocations that are being offered to electric, gas and oil utilities, as well as other industries. No options are available except purchasing allowances to cover CREF's emissions compliance obligations. As the price of allowances inevitably increases, in time this amount could easily exceed one million dollars per year. We are requesting that CARB provide free allowances for the three California waste-to-energy facilities. (CREA)

Comment: The Board should modify the proposed regulations to remove the CO_2e allowance requirement for WTE facilities. Alternatively, the Board should provide free CO_2e allowances for California's WTE facilities pending further investigation by the Board of the considerable environmental benefits of WTE, including GHG mitigation benefits. That would be followed by additional rulemaking to rescind the counterproductive CO_2e allowance requirement for WTE facilities. (LGCRE)

Response: We did not modify section 95852.2 to provide a full exclusion from compliance obligations for waste-to-energy facilities. However, we continued excluding the biogenic fraction of MSW in section 95852.2(a)(7). We also modified this section to remove restrictions on the exclusion when the biogenic fraction of MSW is converted to a clean-burning fuel.

By including these facilities under the cap-and-trade program, the facilities will have an incentive to reduce fossil fuel emissions either through new technology or increased use of biomass-derived fuels. The commenters have been unsuccessful in demonstrating that GHG emissions from waste-to-energy facilities are lower than GHG emissions from diversion of the waste to landfills. Also, from an equity standpoint, we include all electricity generation sources in the cap-and-trade regulation.

E-46. Comment: Biomass-derived fuels should not be subject to a compliance obligation in the Cap and Trade Program. The "Greenhouse Gas Verification Requirements" section of ARB's Staff Report on Mandatory Reporting states that "Any biomass-derived fuels cannot also receive an offset credit in another voluntary or mandatory program and still be an eligible biomass-derived fuel for reporting as biomass CO_2 that would not be subject to an obligation in the cap and trade program." PG&E interprets this to mean that, for example, a livestock manure digester project (e.g. a dairy) that generated and sold offsets and combusted the biogas from that project either as a flare (i.e. stationary combustion) or as a self-generator of electricity would have a cap and trade compliance obligation for those combustion emissions if they were equal to or greater than 25,000 MT CO_2e. PG&E contends that biomass-derived fuel should not be subject to a cap and trade compliance obligation if it comes from a project that also receives offset credits, for the following reasons:

- It is inconsistent with ARB's Compliance Offset Livestock Manure (Digester) Project Protocol. Offsets from livestock manure digester projects, such as those that comply with the ARB Compliance Offset Livestock Manure (Digester) Project Protocol, are from the net change in emissions associated with installing a biogas control system (BCS) at the project's facility. As noted on page 6 and reiterated in Table 4.1 on page 9 of the Protocol, the CO_2 emissions associated with the generation and destruction of biogas (such as through flaring, electricity generation, or combustion as pipeline gas or CNG/LNG) are considered biogenic and are not included in a project's GHG Assessment Boundary. The protocol specifically notes that the CO_2 emissions from combustion of the biogas through flaring, during electric generation, or by an end user of pipeline or CNG/LNG, are excluded from the project's emissions.

- It is inconsistent with approaches taken by the Intergovernmental Panel on Climate Change (IPCC), U.S. EPA, and Department of Energy (DOE). Both the IPCC guidelines for CO_2 emissions from BCS21/ and the EPA in its Mandatory

Reporting of GHG Rule agree that the CO_2 emission are biogenic (as opposed to anthropogenic) and should not be counted towards a facility's GHG emissions, and, are therefore not subject to a compliance obligation. The IPCC Guidelines for National Greenhouse Gas Inventories states that "only fossil CO_2 should be included in national emissions under Energy Sector while biogenic CO_2 should be reported as an information item also in the Energy Sector." IPCC reasons that "CO_2 emissions from livestock are not estimated because annual net CO_2 emissions are assumed to be zero—the CO_2 photosynthesized by plants is returned to the atmosphere as respired CO_2." EPA's Inventory of U.S. GHG Emissions and Sinks specifically states that biomass combustion emissions of "biogenic origin" are excluded because "Fuels with biogenic origins are assumed to result in no net CO_2 emissions, and must be subtracted from fuel consumption estimates." Finally, DOE's voluntary GHG reporting program, 1605(b), states that "carbon dioxide emissions of biogenic fuels do not "count" as anthropogenic emissions under the Framework Convention on Climate Change because the carbon embedded in biogenic fuels is presumed to form part of the natural carbon cycle."

- Without the benefit of both energy and carbon offsets livestock manure digester projects are not cost effective. Even with full credit for carbon offsets and use of the project's biogas for self-generation or sold electricity, Livestock Manure Digester Projects are financially challenging. Although, ARB currently lists nineteen digester projects as operational, there are only eleven digester projects currently in operation in California. Many digesters have shut down for economic and/or operational reasons. In order for these projects to contribute to the State's GHG reduction goals, they need revenue from both the energy value of the biogas and carbon offsets. Finally, if these projects don't get built, there will be an increase in greenhouse gas emissions. (PGE1)

Response: We clarified that combustion emissions from digester biogas will not have a compliance obligation as long as any offset credits earned for methane capture in the digester project do not exceed those calculated using the Global Warming Potentials listed in the IPCC, Second Assessment.

E-47. Comment: I encourage you not to change the biomass provisions that you have proposed in your cap and trade. The treatment of biomass that you have in the law today is fully consistent with the treatment that EPA is developing in the tailoring rule. The tailoring rule progression to date has moved closer to California's treatment of biomass, and we're hoping it will continue to do that. Also, the rule does not assume carbon neutrality for all biomass. It only asserts carbon neutrality for biomass types for which actual carbon neutrality has been demonstrated in scientific studies. The use of the fuels that are listed in section 95852.2 does lead to demonstrable reductions in greenhouse gases when those fuels are used for energy production rather than disposed of in conventional means. (MORRISG)

Response: Thank you for the comment.

E-48. Comment: Kern is a small independent family-owned refiner with no upstream crude oil or downstream retail operations. I'd like to add one item to our written comments. That would be we would like to see renewable diesel added to the source categories for emissions without a compliance obligation. (KERNOIL2)

> **Response:** Section 95852.2 includes the fuel types that are exempted from holding a compliance obligation. The provision for biodiesel exemption does cover renewable biodiesel.

E-49. Comment: Include full life-cycle accounting of biofuel emissions. The proposed regulation excludes emissions from the combustion of biomass-derived fuels; biodiesel, fuel ethanol, municipal solid waste and biomethane from compliance (see section 95852.2). Life-cycle GHG emissions from the production and use of biofuels includes emissions from land-use change, fuel production and fuel consumption. The exclusion of biofuel combustion emissions is appropriate for the organic carbon in the fuel. Other provisions in the regulation account for stationary and transportation emission sources associated with biofuel production. However, the regulations do not account for the GHG emissions resulting from land-use change when crops are grown for fuel. CARB regulations should ensure that the full GHG impacts of biofuel production (e.g. land-use change) are accounted for in the cap and trade program. (CONOCO)

> **Response:** The point of regulation is to address emissions at the capped entities. Land-use emissions are beyond the scope of this regulation. The LCFS does take into account the full lifecycle emissions for biofuels and is a complimentary measure under the cap-and-trade program.

E-50. Comment: The Cap and Trade program will profoundly affect the San Joaquin Valley. Special consideration should be given to the health effects in this region. We share the concern of many public health and environmental justice organizations that the Cap and Trade program currently does not require biomass, solid waste, agricultural crops and waste, woody waste, and dairy and cattle operations to obtain emission allowances for their operations. These processes contribute to greenhouse gas emissions and other forms of air pollution as well. ARB should require these industries to comply fully with all reporting and allowance obligations in AB 32. (CATHCHAR1)

> **Response:** The cap-and-trade program does not allow any covered entity to avoid the existing requirements at the local, state, and federal level to address air emissions that may be harmful to public health. The cap-and-trade program is designed to reduce GHGs and include co-benefits for other air emissions. ARB and local air districts have specific programs designed to control local air emissions. The sources exempt from a compliance obligation are still subject to all other environmental protection regulations.

E-51. (multiple comments)
Comment: I am writing to urge you to amend the proposed cap and trade rule to eliminate the exemption from compliance obligations for forest biomass emissions. (FORMLETTER08)

Comment: Eliminate the exemption from compliance obligations for forest biomass emissions. (LISH)

> **Response:** We do not agree. All forest biomass must be reported and verified to be exempt from a compliance obligation.

E-52. Comment: The apparent intended use of the word "biomass-derived fuel" in the proposed regulations to mean anything that was ever living that is not now fossilized is confusing, since "biomass" has a pre-existing, and different, meaning in the energy industry, as generally referring to the items listed in 95852.2(a)(1), (2), (3) and (4). Biomethane from digesters is generally not considered biomass in the energy industry. See, e.g., California Energy Commission Renewable Energy Facilities Eligibility Guidebook 3rd ed., p. 3 ("biomass or biogas"), page 10 ("biogas" and "biomass" are two separate items on the table), pp.11 and 20, discussing biomass and biogas as completely separate resource categories, and Form CEC-RPS- I A/B (listing biomass and biogas as completely separate resource categories). (WEINSTEIN)

> **Response:** For the purposes of this regulation, we do consider biomethane to be a biomass-derived fuel for all intended purposes.

E-53. Comment: Since most people in the energy industry distinguish "biomass" from the other items in the broad list of fuel sources listed in 95852.2(a), in order to avoid confusion, it may be useful for the proposed regulations to use the word "organic" or "organically derived" rather than "biomass-derived" for the broad, all-inclusive concept for which "biomass-derived" is now used, and redefine and limit the defined term "biomass" to fuels in the nature of 95852.2(a)(1), (2), (3) and (4), to keep "biomass" as used in the regulations within the confines of traditional meaning of the word "biomass" in the energy industry. (WEINSTEIN)

> **Response:** We do not agree. The cap-and-trade regulation applies to more than just the energy industry. We have defined the term biomass for this specific program to include a reference to organic materials.

E-54. Comment: The proposed regulation prescribes, “An entity that has emissions from biomass-derived fuels is required to report and verity its emissions pursuant to the Mandatory Reporting Regulations section 95130 and has a compliance obligation for every metric ton of CO_2e emissions from biomass-derived fuels that would result from full combustion or oxidation of all fuel for emissions identified below.” The proposed regulation then proceeds to specify that source categories for which a compliance obligation ensues, including emissions from source categories not listed under section 95852.2 or emissions from source categories listed under section 95852.2

without the requisite documentation to establish the validity of biomass-derived fuels. The proposed language is unclear. IEP understands the proposed regulation to appropriately exempt from a compliance obligation those fuels that fall within section 95852.2 (assuming proper reporting, etc.). Furthermore, IEP understands that to the extent a biomass facility has a compliance obligation, that obligation will be associated only with the fuel consumed by the facility for which a compliance obligation actually exists, i.e. the calculation will be net of any emissions associated with the fuels indicated in section 95852.2. Modify section 95852.1 as follows:

(a) Emissions from source categories listed under section 95852.2 below are not subject to a compliance obligation;
(b) Emissions from source categories that are not listed under section 95852.2 below are subject to a compliance obligation; or
(c) Emissions, from source categories listed in 95852.2, without information and documentation necessary to establish the validity of biomass-derived fuels which are considered unverifiable pursuant to MRR section 95131(i) and are subject to a compliance obligation. (IEPA)

Response: We modified this section to further clarify our intent.

E-55. Comment: Section 95852.1 (p. A-63) regarding the compliance obligations for biomass-derived fuels contains some wording that appears to be unnecessary and should be removed for clarity. (The summary of and rationale for this section in the ISOR, at IX-39 to 40, is also unclear and should be reviewed). Section 95852.1(b) refers to the biomass verification requirements in section 95131(i) of the Revised MRR. Section 95131(i)(2)(A) of the revised MRR sets out very important (and detrimental) restrictions on the ability to treat emissions from biomass-derived fuels as zero-CO_2-emissions. Biomass-derived fuel purchased under contracts entered into after January 1, 2010, other than contracts for expanded production only, will not count as zero-CO_2-emissions. SCPPA strongly opposes the restriction in section 95131(i)(2)(A) of the revised MRR and will discuss the restriction in its comments on the revised MRR. However, if such a restriction is imposed, given its importance, it should be clearly set out in the Cap and Trade regulation, for example, in the definition of biomass-derived fuel or in section 95852.1 (directly rather than by cross-reference) rather than being included towards the end of a long and technical section headed "Requirements for Verification Services" in the revised MRR. Modify section 95852.1 as follows:

An entity that has emissions from biomass-derived fuels is required to report and verify its emissions pursuant to Mandatory Reporting Regulation section 95131~~0~~ and has a compliance obligation for every metric ton of CO_2e emissions from ~~biomass- derived fuels that would result from full~~ combustion ~~or oxidation~~ of all biomass-derived fuel from the categories ~~for emissions~~ identified below:

(a) ~~Emissions from s~~Source categories that are not listed under section 95852.2 below; or

(b) ~~Emissions, from s~~Source categories listed in 95852.2, without information and documentation necessary to establish the validity of the fuel as a biomass-derived fuel~~s~~ and which are therefore considered unverifiable pursuant to MRR section 95131(i). (SCPPA1, SCPPA5, SMUD2)

Response: The text in the MRR related to the exemption of biomass-derived fuels has been moved into section 95852.1. Restrictions regarding the exemption eligibility for biomass-derived fuels are required to prohibit emissions leakage. AB 32 explicitly requires us to limit emissions leakage in the design of the market program.

E-56. Comment: If ARB must make an adjustment to account for the emissions from combustion of biomass derived fuel, it is preferable that this adjustment be made in the manure offset protocol. The ARB could take into account the project emissions from combusting CO_2 and award a smaller number to offsets, such that the downstream compliance obligation exemption is preserved. This approach is preferable to having a compliance obligation on the gas, which would make it more difficult to market and thereby limit the number of projects undertaken, and the benefits to the State. (ABC)

Response: We have no restrictions on the exemption for combustion emissions from biogas from a manure offset project, other than the offset credits for captured or destroyed methane must not be greater than those calculated using the Global Warming Potentials in the IPCC, Second Assessment.

E-57. Comment: We urge ARB to clarify that a facility which was previously flaring its biogas and now re-directs that gas into productive use (or increases efficiency in its use of biogas) would also qualify for the compliance obligation exemption. (ABC)

Response: We clarified the regulation to exempt from a compliance obligation previously flared biogas now used for useful energy.

E-58. Comment: The proposed regulation language requires that fuel producers that have sold biomass-derived fuel to a California operator before 2010 to continue selling to the same operator in order to retain the compliance exemption. This holds the biomass derived fuel production facility captive to one buyer and gives that buyer an inordinate amount of market power. It unnecessarily restricts biomass derived production capacity that has historically supplied the state from being able to sell to another California buyer, when doing so would have no net impact on emissions or the cap. As long as a verifier can verify that a contract existed with a California buyer, there should be no requirement for the biomass derived fuel facility to continue to sell to the same entity in order to be eligible for the compliance obligation exemption. (ABC)

Response: We clarified the text to allow for exempt biogas that is sold to a capped entity in California to sell to a different capped entity in the state and still be exempt from a compliance obligation.

E-59. Comment: Under section 95852.1 and 95852.2 of the proposed regulations and section 95131(i) of the proposed revised Mandatory Reporting Rule (MRR), the compliance exemption for biomass-derived fuels is limited to: (1) fuel production that was obligated under contract to a California operator prior to January 1, 2010; and (2) fuel that is "associated with an increase in the biomass-based fuel producer's capacity." This restriction does not account for facilities which transport gas to California, but are not specifically under a contract. If an operator can provide concrete evidence (and a verifier can verify) that the output from a biomass-derived fuel was historically flowing to California, then that fuel is equally deserving of the compliance obligation exemption. (ABC)

> **Response:** We modified the text to allow such transferred biogas to be exempt if the fuel can be shown and verified to be combusted in California prior to January1, 2012, or was biogas not previously used to produce useful energy.

E-60. Comment: The American Biogas Council is concerned that some of the restrictions ARB has placed on the ability of biomass derived fuels to qualify for the compliance obligation exemption will have the unintended effect of limiting the nascent growth of the biogas industry. (ABC)

> **Response:** The eligibility requirements are to prohibit emissions leakage as required under AB 32.

E-61. Comment: The American Biogas Council strongly recommends that ARB allow facilities earning offsets under a digester protocol to claim a compliance obligation exemption. The American Biogas Council believes that biogas from manure digester offset projects is carbon neutral, and should qualify for the same compliance obligation exemption provided for other biogenic sources. In an offset project, an upstream offset is awarded for the conversion of methane to carbon dioxide (CO_2). The compliance obligation exemption, on the other hand, is awarded on the basis that the emissions from biomass derived fuel are biogenic. These are two distinct attributes and should be treated as such. (ABC)

Comment: Biogas from manure digester offset projects is carbon neutral, and should qualify for the same compliance obligation exemption provided for other biogenic sources. The emissions generated from biogas combustion are carbon neutral whether the biogas originated from a manure digester, a landfill, a wastewater treatment plant, or any other biogenic source. The fact that the manure digester is also receiving offset credits is no bar to the gas being recognized as carbon neutral. Offset credits are awarded for emission reductions or sequestration beyond a business as usual baseline. The digester will receive the same quantity of offset credits whether it flares the methane or puts it to productive use in generating electricity because the offset credits are awarded solely for the conversion of methane to CO_2. If the regulations do not provide a compliance exemption, the program runs the risk of encouraging livestock manure digester operators simply to flare methane instead of putting the gas to productive use through electricity generation. If ARB is concerned that the CO_2 emissions that result from methane digester biogas combustion are not being taken into account if a digester project receives offset credits for the full CO_2e value of the methane combusted and the use of the biogas receives a downstream compliance exemption, then CERP urges ARB to change the methane digester protocol rather than withhold the compliance exemption. The quantity of credits earned by a livestock manure digester project should be the difference between the baseline CO_2e and the actual CO_2 that is emitted due to the combustion of captured methane. If the protocol was so changed, there would be no justification for imposing a compliance obligation on livestock manure digester biogas downstream. The biogas is carbon neutral, and is as deserving of the compliance exemption as the other exempted sources. Imposing a downstream compliance obligation on methane digester biogas projects is highly problematic. These problems could be avoided by reducing the quantity of offset credits awarded upstream to account for the CO_2 emissions generated by the methane combustion and applying the biogas compliance exemption to biogas from methane digester offset projects. (CERP2)

> **Response:** We clarified the text to allow for biogas from a digester offset project to be exempt from a compliance obligation for its combustion emissions. The offset project only credits the capture and destruction of methane. The exemption applies to the combustion CO_2.

E-62. Comment: The American Biogas Council strongly recommends that ARB apply the biogas compliance exemption in a uniform manner, such that any facilities which have historically been providing biogas to a California entity remain eligible for the compliance obligation exemption. (ABC)

> **Response:** The compliance obligations are assessed at the covered entity, not at the fuel supplier, until 2015. In 2015, the fuel suppliers in California are subject to the cap, and biomass-derived fuels are exempt if they meet specific criteria in the regulation.

E-63. Comment: CARB's Low Carbon Fuel Standard (LCFS) establishes a global best practice for accounting for the GHG intensity of fuels. Through the development of the LCFS, the world has learned that biofuels can have greatly varying lifecycle carbon emissions, including important impacts related to land-use changes. Linking the cap & trade system to the LCFS to account for the carbon content of transportation fuels would support the goals and successful outcomes of both policies. Certain investigations within the LCFS are still on going, such as the Expert Workgroup on food versus fuel issues, and should be reviewed before any such exemptions are finalized.

We recommend allowing fuel providers the flexibility to choose between two options: 1) require allowances to cover the carbon content of the fuel, as proposed for other liquid transportation fuels; or 2) allow use LCFS accounting tools to determine the GHG burden of the fuel in order to adjust the compliance obligation.

The currently proposed exemption provides an implicit subsidy for surface transportation biofuels, regardless of their GHG profile. For example, a $20/ton GHG allowance price translates into a price advantage for conventional ethanol (on top of existing federal subsidies) equivalent to about $0.16-$0.20 per gallon of gasoline-equivalent. Conventional ethanol would also receive a competitive advantage over lower carbon alternatives, such as advanced biofuels that are a focus of in-state research and development investments and electricity and hydrogen meeting the 33 percent renewable portfolio standard. (ICCT1, ICCT2)

> **Response:** Lifecycle emissions are beyond the scope of this regulation. Any direct GHG reductions from covered entities as a result of LCFS would be appropriately recognized under the cap-and-trade program by a decrease in the compliance obligation for the emissions associated with the combustion of that fuel type. While that relationship is not a direct relationship, as one is carbon intensity and the other is actual emissions, we believe the current design of the cap-and-trade program to reduce overall GHG emissions is not in conflict with the LCFS.

E-64. Comment: In support of the ambitious goal of AB 32 to reduce California's GHG emissions to 1990 levels by 2020, CARB has estimated that ethanol emissions, as currently exempted from the cap and trade proposal, would hold steady at about 5 million metric tons per year from 2008 to 2020. There are many reasons why sales from ethanol and other transportation biofuels (not covered by the proposed cap) will likely grow in coming years: 1) ethanol blend levels in typical gasoline are increasing, currently to E10 (i.e., 10 percent ethanol from just under 6 percent) and potentially to E15 in the future; 2) the national Renewable Fuels Standard will more than double the amount of biofuels nationally; and 3) California is investing heavily in E85 infrastructure. While the effect of increasing sales volumes on GHG emissions depends in part on how these biofuels are produced, well-aligned regulatory programs are needed to ensure that the sales mix includes a rapidly increasing share of the lowest GHG biofuels. CARB's ambitious plan to meet AB 32 goals leaves no room for growth in emissions outside the cap, as might be expected from expansion in biofuels. (ICCT1, ICCT2)

> **Response:** The emissions cap from this program includes GHG emissions from fossil fuels. By allowing alternatives to fossil fuels that are not under the cap, we believe there is room for a growth in emissions from non-fossil sources outside the cap. Biomass-derived fuels that can be verified are exempt from a compliance obligation. There is no limit to how many emissions a covered entity may report and verify as emissions from biomass-derived fuels.

E-65. Comment: CAL FIRE supports sections 95852.1 and 9582.2 addressing biomass-derived fuel emissions. These sections require reporting of all biomass derived fuel emissions but exempt certain activities and conditions from allowance obligations, including wood and wood wastes generated from timber harvests permitted under the FPA, fuel reduction purposes, and stand improvement activities, so long as the emissions are documented and verified. CAL FIRE supports the sustainable utilization of forest wood waste for bioenergy production as a means of encouraging forest health treatments and contributing to California's renewable energy goals to reduce fossil fuel consumption through biomass energy generation. (DFFP1, DFFP2)

Response: Thank you for the support.

E-66. Comment: Support activities that encourage the recovery, recycling and reuse of waste materials. Do not allow CO_2 emissions from biomass energy and fuels to be considered carbon neutral. Landfill methane or emissions from burning waste should not be considered "carbon neutral", especially in light of the preferable environmental alternatives of composting and AD that will provide greater overall emissions reductions. Require waste-to-energy facilities to be subject to a GHG emissions cap. Do not consider waste-to-energy biogenic. Develop offset protocols that can create credits for the use of recycled materials. (SFMAYOR1)

Response: The regulation does include waste-to-energy facilities under the cap. ARB continues to work closely with its sister boards to evaluate alternatives to landfilling. Offset protocols must address direct reductions of GHG's at a project site for emissions that are not under the cap.

E-67. Comment: Section 95852(b) (p. A-62) establishes the compliance obligation for first delivers of electricity. This is a key provision for first delivers of electricity, so it is important that it is clear and correct. However, as currently drafted, this provision suffers from several defects:

- Section 95852(b) states that there is a compliance obligation for every metric ton of CO_2e for which a positive or qualified positive verification statement is issued. However, the report that a first deliverer of electricity is required to prepare and have verified under the revised MRR contains information about more sources of emissions than those for which the reporting entity has a compliance obligation. (See for example the information required to be reported under sections 95111(a)(7), (c)(1), (c)(5) and (g)(5) of the revised MRR). The subset of verified emissions that form the compliance obligation should be clearly identified.

- Section 95852(b) states that in addition to the emissions in the verification statement, the compliance obligation includes emissions from stationary combustion or from imported electricity. This incorrectly implies that there are emissions from stationary combustion or from imported electricity that are not included in the verification statement and do not need to be verified.

- Section 95852(b) should exclude from the compliance obligation emissions associated with facilities with emissions below 25,000 metric tons of CO_2e per year, as those emissions are not covered under section 95812(b)(2) (p. A-40). The reference to the first deliverer of electricity being covered under section 95812(b)(2) is not sufficient, as a first deliverer may have one facility that exceeds the threshold and one that does not.

- Section 95852(b) should exclude from the compliance obligation CO_2 emissions from the combustion of biomass-derived fuels listed in section 95852.2 and verified in accordance with section 95131(i) of the revised MRR.

Modify section 95852(b) as follows:

(b) First Deliverers of Electricity. A first deliverer of electricity covered under sections 95811(b) ~~and 95812(b)(2)~~ has a compliance obligation ~~for every metric ton of CO2e emissions for which a positive verification statement or qualified positive verification statement is issued, and~~ for every metric ton of CO_2e ~~of stationary combustion~~ emissions (subject to section 95852(h)) from electricity generating facilities in California, and ~~or~~ emissions associated with electricity imported into California from a source in a jurisdiction where a GHG emissions trading system has not been approved for linkage by the Board pursuant to subarticle 12, in each case where the thresholds set out in section 95812(b)(2) have been exceeded and for which a positive or qualified positive verification statement is issued. (SCPPA1)

> **Response**: We modified this section and added section 95852(b)(7), which contains an equation summing emissions with a compliance obligation. Staff has clarified the emissions that result in compliance obligation. This clarification includes clearly stating that the obligation is for the emissions that have a positive or qualified positive verification statement and where set thresholds have been exceeded.

E-68. Comment: Comments submitted to CARB by CBE in May of 2008 on the Scoping Plan identified, based on CARB data, methane emissions that are exempt from regulation. For example, three categories of Stationary Sources listed (Fuel Combustion, Petroleum Production and Marketing, and Industrial Processes) emitted about 466 tons per day (about 170,000 tons methane per year) of exempt compounds, which is likely to be mostly methane. This is about 4 million tons CO_2e per year. There is no reason to continue exempting these emissions, either for smog, or for GHG impacts. It is now known that methane is a considerable contributor to smog, as also discussed in this earlier comment. AB 32 requires the maximum technologically feasible GHG reductions of carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride. Carbon is only one GHG. Furthermore, CARB should remove entirely the methane exemptions for all sources in the state, including transportation sources. CBE proposed this, and CARB found it to be a feasible reduction measure, but never implemented it. Now CARB should evaluate adding this measure as a complementary reduction, as an alternative to the current Cap and Trade proposal, in order to achieve the maximum technologically feasible reductions. (CBE1)

> **Response:** Methane emissions from combustion are covered under the program. Methane emissions from fugitive and vented sources are not covered because of the difficulties to accurately quantify them. Where we believe we

have accurate accounting and measurement methods for fugitive and vented sources, those are included under the cap. However, some fugitive and vented emissions may be covered under direct regulations by ARB in the future.

E-69. (multiple comments)
Comment: Only a fraction of oil and gas facilities are utilizing best practices to minimize fugitive emissions. By excluding these sources from the program, CARB is failing to encourage covered facilities to reduce fugitive emissions, and preventing the opportunity for large operators to take advantage of low-cost emissions reduction opportunities. (EDF1)

Comment: EDF recommends CARB remove the blanket exemption for fugitive emissions from the oil and gas sector and develop a framework to hold operators of oil and gas extraction sites accountable. With regard to the justification for the exemption in the ISOR document, (page IX-41), the reasoning given is that "entities whose aggregate emissions include fugitive emissions from the activities described will not count those emissions toward their total compliance obligation when reporting." [Refers to Section 95852(f)] Such an explanation is not reasoning, but rather a re-description of the exemption itself. EDF requests the agency provide a more detailed explanation of its reasoning for this exemption in the Final Statement of Reasons (FSOR) to be published when the rule is presented as a final agency action to the Office of Administrative Law. (EDF1)

Response: Fugitive, process, and vented emissions from sources as specified in section 95852.2(b) are exempt from holding a compliance obligation under the cap-and-trade regulation. This exemption harmonizes our regulation with the Federal EPA Mandatory Reporting Requirements. Accurate quantification of fugitive emissions at a level of accuracy sufficient for cap-and-trade would be technically difficult, very costly and time intensive. A large oil and gas producer may have thousands of components spread across a large geographic area. While labor-intensive methods are available to quantify fugitive emissions, determining the time period over which the leak has been occurring would require repeated measurements at a frequency that would not be practical given the large number and geographic distribution of these fugitive sources. If quantification methods are developed to provide accurate accounting of these emissions, they would potentially be included in the cap as part of a future rule amendment.

Point of Regulation

E-70. Comment: We support the transportation fuels sector's upstream point of regulation. (CPC1, CPC2, SONOMAFCC, FRIEDENBERG, FORMLETTER01, HANSON)

Response: Thank you for the support.

E-71. Comment: The CO_2 content of fuels should be regulated at the level of the fuel producers, in order to increase the efficiency of the regulation and provide incentives for CO_2 reductions. (BMWGROUP)

> **Response:** The cap-and-trade regulation imposes a compliance obligation for fuels at a so-called "upstream" point. Thank you for the support.

Opt-In Entities

E-72. (multiple comments)
Comment: We are concerned about the provision that would allow opt-in or voluntary associated facilities from purchasing allowances at ARB auctions. Further restrictions are needed to insure that opt-in or voluntary associated entities will not purchase and retire allowances thereby limiting the market and driving up costs of the limited pool of allowances. (ACC1)

Comment: The proposed rule includes two concepts that erode the cap. The first is the ability of certain entities to "opt in" to the program if they are among the classes of entities covered by the proposed rule but which do not emit CO_2e in excess of the applicable thresholds for the first compliance period. These "opt in" entities would consume part of the cap (no additional allowances would be available to cover the opt in entities), and would compete for allowances with entities that are required to submit compliance instruments. The second concept is the ability of non-covered entities to purchase allowances (or offsets) and retire them voluntarily, even though they are not required to submit allowances. Each of these options erodes the available pool of allowances and effectively reduces the cap available to covered entities that require allowances in order to survive economically. (HOR)

Comment: Prohibit entities that are not in the original compliance group from purchasing allowances and submitting them for retirement. Regulated entities should be able to purchase allowances for their own compliance purposes without being unnecessarily held up by unregulated entities. The purpose of the allowance market is to make the process more efficient and not to give third parties the ability to shut down existing businesses. (HOR)

> **Response:** We disagree. We do not think that it is appropriate to place further restrictions on non-covered entities participating in the cap-and-trade program. We have developed market rules associated with purchase and holding limits to address some of these concerns. We expect that the market effect from small opt-in and non-covered entities will be negligible in the context of the entire market.

Voluntary Retirement of Compliance Instruments

E-73. (multiple comments)
Comment: The Utilities strongly encourage CARB to restrict the voluntary retirement of compliance instruments to offsets only. The voluntary retirement of allowances by non-covered entities results in a reduction of the overall cap level for covered entities. A restriction on voluntary retirement to offsets only would provide a direct GHG reduction opportunity through the creation and retirement of CARB qualified and approved offsets while not increasing the cost burden to covered entities. Modify section 95922(d) as follows:

(d) Voluntary Retirement of Compliance Instruments.

(1) An entity registered pursuant to section 95930 may voluntarily submit offsets ~~any compliance instrument~~ for retirement.

(2) To voluntarily retire an offset ~~compliance instrument~~, the registered entity submits a transaction report to the accounts administrator listing its account number, the serial numbers of the [offsets] ~~instruments~~ to be retired, and the ARB Retirement Account as the destination account. (MID1)

Comment: The voluntarily retirement of compliance instruments must be done in an open and transparent way as this action directly impacts those covered entities that have a compliance obligation. Since the retirement of allowances by VAEs results in a reduction of the overall cap level and increases the cost burden for covered entities, the Utilities strongly support a provision whereby VAEs would only be allowed to retire offsets. This adjustment would provide VAEs with a direct GHG reduction opportunity through the creation and retirement of CARB qualified and approved offsets. In addition, such an approach would protect consumers from an unjustified price escalation due to an unduly constrained allowance market. (MID1)

Comment: NCPA is concerned that voluntarily associated entities (VAE) could have a detrimental impact on the ability of Covered Entities to obtain the allowances they need at costs less than the Reserve Account price. The proposed regulation needs to ensure that VAE participation in the market is designed so that entities with a compliance obligation are not adversely impacted. Such participation creates significant market power and market manipulation potential, and could have unintended consequences for compliance entities. While the ISOR advocates the inclusion of these entities as a means to allow entities without a compliance obligation to “voluntarily retire compliance instruments for the benefit of the environment” and believe that “allowing additional participants also increases market liquidity and creates a larger market,” (ISOR, p. IX-15), this can still cause adverse consequences for Covered Entities. The general economic theory is that more market players will lower costs; however, that may not necessarily be the case in practice. For example, even those with the most altruistic intent and the financial means to affect their intent to simply retire emissions could wreak havoc on the price of available allowances for those that need them for a compliance obligation.

NCPA appreciates the limitations that have been placed on the number of allowances that can be purchased by the VAE and restrictions on their ability to purchase from the Reserve Account, but believe that these limitations fall short of adequately addressing the potential adverse impacts. NCPA recommends that participation by VAEs be further restricted to surrender of offset allowances only, and that all of the transactions conducted through section 95831(c)(3) be publicly noticed and transparent. In the alternative, NCPA recommends that VAEs be able to only voluntarily surrender no more than 1 percent of California GHG allowances annually. (NCPA1)

> **Response:** We believe the market rules have been structured in a way to address these concerns. This includes provisions for purchase and holding limits. We believe the impact of voluntary participants will be negligible on the market and on the ability of covered entities to comply with the regulation.

E-74. Comment: NCPA recommends that section 95830(d)(3) be revised to require a registration deadline for VAEs, as all other auction participants must register with CARB a certain number of days prior to the auction. (NCPA1)

> **Response:** Section 95912(c) provides that any entity, whether a VAE or an entity with a compliance obligation, that is intending to participate in an auction must complete an auction registration 30 days in advance of the auction. Therefore, no change is needed.

Threshold for Compliance Obligation

E-75. Comment: The Utilities request clarification of subsection 95812(b) and how the entity and facility thresholds operate together. Clarify how facilities that do not exceed the facility threshold are factored in determining an entity's threshold and compliance obligation. The confusion occurs given the use of the word "aggregated." The language is circular, but seems to indicate that only facilities that exceed the facility threshold are to be counted in the aggregation. This reading makes the concept of aggregation redundant since one facility would tip the entity over the threshold. (MID1)

> **Response:** We removed the term "aggregated" from section 95812(b).

E-76. Comment: The last sentence of section 95812(b)(2)(B) (p. A-41) refers to specified sources that emit 25,000 metric tons of CO_2e per year. This provision is incomplete, as the treatment of facilities with emissions higher or lower than this level is not specified. This section should be corrected by adding the words "or more" as follows:

> (B) The threshold for an electricity importer from a specified source which emits 25,000 <u>or more</u> metric tons of CO_2e per year is zero. (SCPPA1)

> **Response:** We agree and modified this section accordingly.

Surrender of Compliance Instruments

E-77. (multiple comments)
Comment: To clarify draws from compliance account, modify section 95856(f)(3) as follows:

> (3) The Triennial Surrender obligation shall equal the Triennial Compliance Obligation calculated pursuant to section 95853 less allowances and offset credits <u>already surrendered</u>. (NCPA1)

Comment: SMUD requests clarification of the aforementioned missing words in section 95856(f)(3). If we are correct in our interpretation, the section should read as shown below, but if incorrect, ARB should clarify what the actual intent is of this section. Modify section 95856(f)(3) as follows:

> (3) The Triennial Surrender obligation shall equal the Triennial Compliance Obligation calculated pursuant to section 95853 minus less <u>compliance instruments</u> ~~allowances and offset credits~~ <u>previously surrendered for the compliance period via Annual Surrender obligations.</u> (SMUD1)

Comment: Section 95856(f)(3) (p. A-71) states that the triennial surrender obligation equals the triennial compliance obligation "less allowances and offset credits." This appears to be incomplete. The ISOR states (at IX-49) that "the triennial surrender obligation will account for compliance instruments already surrendered pursuant to the annual compliance obligation." Modify section 95856(f)(3) as follows:

> (3) The Triennial Surrender Obligation shall equal the Triennial Compliance Obligation calculated pursuant to section 95853 less allowances and offset credits<u> that have been surrendered to meet annual compliance obligations in the relevant compliance period pursuant to sections 95855 and 95856</u>. (SCPPA1)

Comment: The Utilities request clarification in subsection 95856(f)(3) regarding the proper calculation of the triennial surrender obligation. To be clear on what allowances and offsets are being factored, modify section 95856(f)(3) as follows:

> (3) The Triennial Surrender obligation shall equal the Triennial Compliance Obligation calculated pursuant to section 95853 less allowances and offset credits <u>already transferred to the covered entity's compliance account for the Compliance Period.</u> (MID1)

> **Response:** We agree and modified this section to clarify that compliance instruments already surrendered to fulfill the annual compliance obligation for years in the compliance period will count toward a covered entity's triennial compliance obligation.

E-78. (multiple comments)
Comment: Section 95856(g)(1) (p. A-71) states that the Executive Officer will retire the compliance instruments surrendered. "Surrender" is not defined. It should be clarified that the Executive Officer will only retire the number of compliance instruments equal to the compliance obligation, leaving any excess compliance instruments in the holder's compliance account for use against future compliance obligations. Modify section 95856(g)(1) as follows:

> (1) Retire the <u>number of</u> compliance instruments <u>equal to the triennial compliance obligation</u>~~surrendered~~. (SCPPA1)

Comment: To clarify draws from compliance account, modify section 95856(g) as follows:

(g) When the Executive Officer has determined the covered entity has met its surrender obligations, the Executive officer shall:

> (1) Retire <u>only</u> the <u>number</u> of compliance instruments <u>necessary to meet the Triennial Surrender Obligation of the covered entity pursuant to subsection (f) above</u> ~~surrendered~~; and . . . (NCPA1)
>
> **Response:** We do not agree that the suggested change is necessary because surrender is adequately described in section 95856.

E-79. Comment: Deadlines should be established for ARB decision-making processes to provide entities with a degree of certainty. Modify section 95856(e)(3) as follows:

> (3) When the data review and reconciliation process, as stated in section 95104 of the Mandatory Reporting Regulation, for a covered entity has concluded, the Executive Officer shall issue a final determination of the covered entity's triennial compliance obligation <u>within 30 days</u>. (CCEEB1)
>
> **Response:** We removed this section from the regulation as it was unnecessary, so the comment is no longer relevant. Data reported under MRR is subject to any reviews and appeals between the reporter and verifier. As this data feeds directly into the cap-and-trade program, another review process would be redundant.

E-80. Comment: There should not be an annual compliance obligation in the same year as the triennial compliance obligation. Although the cap and trade regulation is structured around three-year compliance periods, sections 95853, 95855, and 95856 establish annual and triennial compliance obligations and lay out when these obligations must be met through surrender of sufficient allowances. In the case of annual compliance obligations, the partial surrender required is 30 percent of verified emissions from the previous year, and this amount is due by July 15 of the following year for electric utilities. In the case of the triennial compliance obligation, occurring at the end of the compliance periods established in the regulations, the surrender required is generally 100 percent of the verified emissions from the three-year compliance period, due on November 1 of the following year. Section 95856(f)(3) is intended to suggest, in SMUD's opinion, that the amount of compliance instruments that should be surrendered is the amount needed for triennial compliance minus the amount already surrendered via annual compliance surrender, but missing words obscure the meaning of this section. SMUD believes that there should not be an annual surrender in the same year as the triennial surrender, as the two surrender obligations in the same year increase transaction costs unnecessarily. Modify section 95855 as follows:

<u>(c) there is no annual compliance obligation in the same year in which there is a triennial compliance obligation.</u> (SMUD1)

> **Response:** We agree and added section 95856(d)(3) to clarify that there is no annual compliance obligation in years 2015, 2018, and 2021.

E-81. Comment: After initially determining an entity's compliance obligation, the Executive Director should provide an opportunity for the entity to query the determination. Section 95856(e)(3) (p. A-71) appears to provide for such a process by referring to a "data review and reconciliation process, as stated in section 95104 of the Mandatory Reporting Regulation." However, section 95104 of the revised MRR does not contain any provisions relating to data review and reconciliation. Provisions for such a process, incorporating an opportunity for covered entities to query determinations and present further evidence, should be drafted and included in the revised MRR or the Cap and Trade regulation, and there should be a correct cross-reference in section 95856(e)(3) to that new provision. (SCPPA1)

> **Response:** We removed section 95856(e)(3) from the regulation, so a cross-listing with the corresponding MRR section is no longer necessary. The GHG data report will be verified through an interactive process between a third-party verifier and the covered entity. Any discrepancies should be found and corrected as part of this process. The compliance obligation will be based on the verified emissions. We do not believe another review of the reported data is necessary once the verification opinion is submitted.

E-82. Comment: The Utilities would like clarification as to how the annual compliance obligation is calculated in the event of a "non-qualified verification" per CARB's Mandatory Reporting Regulations (MRR) for the previous year's emissions report. (MID1)

> **Response:** We modified the cap-and-trade regulation to clarify that emissions will be assigned pursuant to section 95131 of the Mandatory Reporting Regulation. We also modified the MRR regulation to describe how emissions would be assigned.

E-83. Comment: Modify section 95852(h) as follows:

(h) The compliance obligation is calculated based on the <u>CO_2e</u> ~~sum of~~ emissions <u>determined from (i) emissions</u> ~~of CO_2, CH_4, and N_2O resulted from combustion of fossil fue.~~ (CAPCOA1, CAPCOA2)

Response: We removed this section of the regulation, so the suggested edit is no longer relevant. We added new section 95852(i), which describes the calculation of the compliance obligation.

E-84. Comment: Section 95855 (p. A-69) provides that an entity has an annual compliance obligation for any year when it is a covered entity, unless it first becomes a covered entity in the third year of a compliance period. This exemption does not seem sufficient. There is only a short period between when an entity may first discover that it has become covered and when the first annual compliance obligation becomes due. It may be difficult for a newly-covered entity to obtain compliance instruments in this period. The exemption from the annual compliance obligation should be for the first year in which an entity becomes a covered entity, regardless of whether that year is the first, second, or third year of a compliance period. (SCPPA1)

Response: We do not believe that an exemption is warranted and that entities should conduct due diligence in monitoring their emissions levels as reporting is already required for entities that exceed 10,000 $MTCO_2e$.

E-85. Comment: Section 95855(b) refers to "positive or qualified positive GHG emissions reported from the previous data year." This appears to be a reference to positive or qualified positive verification statements, which are separate from emissions reports. This should be clarified. Modify section 95855 as follows:

(a) An entity has an annual compliance obligation for any year when the entity is a covered entity except for the <u>year in which the entity initially exceeds the relevant threshold in section 95812.</u> ~~condition specified in section 95853(d); and~~

(b) The annual compliance obligation for a covered entity equals thirty percent of <u>covered emissions reported in a</u> positive or qualified positive <u>verification statement for</u> ~~GHG emissions reported from~~ the previous data year. (SCPPA1)

Response: We agree and modified section 95855(b) with a change similar to that suggested by the commenter.

E-86. (multiple comments)
Comment: The Utilities have developed a timeline showing the various proposed deadlines for electric utilities that are covered entities. The timeline is included as Attachment A to these comments. The Utilities have submitted a request to CARB staff working on the changes to the MRR that the verification deadlines be consolidated to October 1 each year for both operators and suppliers of electric power entities. Similarly, the Utilities are requesting here that the annual and triennial surrender deadline be consolidated to November 1 in an effort to increase administrative simplicity

and harmonization for the covered entity, especially given that these deadlines are subject to enforcement action. The Utilities believe that the annual surrender dates must follow verification, further justifying a November 1 date. Modify section 95856(d) as follows:

(d) Deadline for Annual Surrender. For any year in which a covered entity has an annual compliance obligation pursuant to section 95855, it must fulfill that obligation by November 1 of the calendar year following the filing of an entity's reports pursuant to section 95103 of the MRR.

~~(1) By May 15 of the calendar year following the year for which the obligation is calculated if the entity reports by April 1 pursuant to section 95103 of the MRR.~~
~~(2) By July 15 of the calendar year following the year for which the obligation is calculated if the entity reports by June 1 pursuant to section 95103 of the MRR.~~
(MID1)

Comment: The deadline for annual surrender should be aligned with the three-year compliance period surrender deadline, page A-70. Subparagraph (b) on page A-69 indicates the annual compliance obligation equals 30 percent of a positive verification statement or qualified positive verification statement from the previous year. LADWP supports this annual surrender obligation as a reasonable balance between providing needed flexibility and identifying entities at risk of default. LADWP recommends further streamlining of the surrender deadline to a single date of November 1 of the following calendar year, rather than two separate dates of May 15 and July 15. Vertically integrated electric utilities have two reporting deadlines, one for facility-level reporting, and another for entity-level reporting. A single annual surrender deadline that occurs after these two dates provides for less complexity. Modify section 95856 as follows:

"Compliance Period 1 Annual Surrender Deadlines:
1) Thirty percent of 2012 emissions are due November 1, 2013
2) Thirty percent of 2013 emissions are due November 1, 2014
3) Remaining emissions for 2012-2014 are due November 1, 2015

Compliance Period 2 Annual Surrender Deadlines:
4) Thirty percent of 2015 emissions are due November 1, 2016
5) Thirty percent of 2016 emissions are due November 1, 2017
6) Remaining emissions for 2015-2017 are due November 1, 2018

Compliance Period 3 Annual Surrender Deadlines:
7) Thirty percent of 2018 emissions are due November 1, 2019
8) Thirty percent of 2019 emissions are due November 1, 2020
9) Remaining emissions for 2018-2020 are due November 1, 2021." (LADWP1)

Comment: Section 95856(d) (p. A-70) sets surrender deadlines of May 15 or July 15 for the annual compliance obligation. However, the annual compliance obligation is calculated based on "positive or qualified positive GHG emissions." Qualified or positive qualified verification statements are not due until September 1 or October 1. The surrender deadline for the annual compliance obligation should be changed to occur after the due date for verification statements. To align with the surrender deadline for the triennial compliance obligation, the due date for the annual compliance obligation should be November 1. For the third year of each compliance period, the annual compliance obligation and the triennial compliance obligation would be due together. Modify section 95856(d) as follows:

(d) Deadline for Annual Surrender. For any year in which a covered entity has an annual compliance obligation pursuant to section 95855, it must fulfill that obligation by November 1 of the following calendar year. For any year in which the covered entity's annual compliance obligation and triennial compliance obligation coincide, the obligations shall be satisfied coincidentally.~~:~~

> ~~(1) By May 15 of the calendar year following the year for which the obligation is calculated if the entity reports by April 1 pursuant to section 95103 of the MR;~~
> ~~(2) By July 15 of the calendar year following the year for which the obligation is calculated if the entity reports by June 1 pursuant to section 95103 of the MRR.~~
> (SCPPA1)

Comment: WSPA recommends ARB change the deadline for annual surrender from May 15 to November 1. Section 95855(b) requires that covered entities surrender 30 percent of their obligations by May 15, based on the previous year's emissions report. As verified reports are not available until September 1, the surrender obligation would be via an unverified report. If the unverified report contains errors that are subsequently corrected, the covered entity could be liable for penalties. (WSPA1)

Comment: Amend annual surrender deadline to date when verified emission reports are available. November was selected to coincide with triennial surrender date. Modify section 95856(d) as follows:

(d) Deadline for Annual Surrender. For any year in which a covered entity has an annual compliance obligation pursuant to section 95855, it must fulfill that obligation

> (1) By ~~May 15~~ November 1 of the calendar year following the year for which the obligation is calculated if entity reports by April 1 pursuant to section 95103 of MRR;
> (2) By July 15 of the calendar year following the year for which the obligation is calculated if... (CCEEB1)
>
> **Response:** We agree and changed the surrender deadline to November 1. We have also modified the text so that in the year after the compliance period ends there is only a triennial surrender obligation, not an additional annual surrender obligation.

E-87. Comment: Section 95856(d)(2) requires the annual surrender of allowances within 45 days of when the facility has reported the previous year's GHG emissions but prior to having the emission reports verified. Praxair recommends that CARB amend this provision and allow covered entities until 45 days after the GHG emissions report has been reviewed and passed the required verification process. (PRAXAIR)

Response: We agree and extended the deadline until November 1.

E-88. Comment: Section 95856(e)(3) provides for the Executive Officer to issue a final determination of a covered entity's triennial compliance obligation after a data review and reconciliation process. No timeframe for the Executive Office to issue these final determinations is specified. An entity should not be required to fulfill its triennial compliance obligation until after it has received the final determination. Modify section 95856(f)(1) (p. A-71) as follows:

The covered entity must transfer sufficient valid compliance instruments to its compliance account to fulfill its triennial surrender obligation by the later of November 1 of the year following the third year of the compliance period, or 15 days after the covered entity receives the Executive Officer's final determination under section 95856(e)(3). (SCPPA1)

Response: Since section 95856(e)(3) has been removed from the regulation, the suggested change is no longer relevant. This section was removed as the data used to establish the compliance obligation is already subject to review and appeal under the MRR.

E-89. Comment: Section 95853 (p. A-67) states that triennial compliance obligations are calculated based on total verified emissions. However, several categories of emissions that are reported by a first deliverer of electricity and verified in a verification statement are not used to calculate that entity's compliance obligations. Thus, the term "total verified emissions" should not be used as a basis for computing an entity's compliance obligations. A different term such as "total verified covered emissions" should be defined with reference to section 95852 and then used throughout section 95853 in place of every reference to "total verified emissions." Modify section 95853(a) as follows:

(a) The covered entity's triennial compliance obligation in this situation is calculated as the total verified emissions specified in section 95852 as constituting a covered entity's compliance obligation ("covered emissions") from all three data years of the compliance period. (SCPPA1)

Response: We agree and modified the regulation with similar text.

E-90. (multiple comments)
Comment: The proposed regulation should provide greater flexibility in meeting the compliance obligations by removing some temporal restrictions on the purchase of allowances. The proposed regulation would not allow a regulated entity to procure emissions allowances corresponding to a year later than when the emissions actually occurred. This restriction could create a compliance hurdle in meeting the triennial

compliance obligation, which is due in November of the first year following the end of the triennial period. If a regulated entity discovers it does not have enough emissions allowances at the end of the triennial period (e.g., after 2014), the regulated entity would only be able to procure emissions allowances in auctions that have a previous year's vintage (e.g., allowances from 2012-2014, but not 2015). While it is understandable that ARB would seek to limit unnecessary delays in compliance, there are legitimate reasons that a covered entity may need to secure some allowances in a subsequent annual period. Accordingly, ARB should not extend its temporal restrictions to the triennial compliance period. (PACIFICOR1)

Comment: The proposed regulation would not allow a covered entity to procure emissions allowances from a year later than the year the emissions were actually emitted (section 95856(b)(2), p. A-70). This restriction could create a compliance hurdle in meeting the triennial compliance obligation, which is due in November following the end of the triennial period. If a regulated entity discovers it does not have enough emissions allowances at the end of the triennial period (i.e., after 2014), the regulated entity would only be able to procure emissions allowances in auctions that have a previous year's vintage (i.e., allowances from 2012-2014, but not 2015). While it is understandable that CARB would seek to limit compliance procrastination, there are legitimate reasons related to variance in consumer demand for product or advantageous market conditions for product manufacture that may result in a covered entity needing to secure some allowances in a subsequent annual period, particularly where its operations are not easily forecasted or are subject to demand drivers outside of its control. Accordingly, CARB should relax its temporal restrictions to the triennial compliance period to provide some flexibility in meeting obligations that arise from market conditions or operations late in the compliance period. (PRAXAIR)

> **Response**: The regulation does not hinder an entity's ability to procure allowances for the current compliance period. However, the regulation does not allow allowances from the current year to meet past triennial compliance obligations. We believe this requirement is necessary to ensure the environmental integrity of the cap. We believe that borrowing should be limited to the purchase of allowances from the Allowance Price Containment Reserve. We anticipate a secondary market in which allowances from past vintages will be available for procurement. The program is also designed to promote due diligence on the part of the entity to monitor and acquire compliance instruments in a timely manner.

E-91. Comment: CARB should clarify which allowances can be used for compliance in a given year. Section 95856(b)(2) states that with limited exceptions, a compliance entity may only use a compliance instrument "issued from an allowance budget year within or before the year during which the compliance obligation is calculated." SCE requests that CARB clarify whether this "compliance obligation" is calculated in the year on which the payment comes due (e.g., 2015 for the first compliance period) or in the year in which the emissions were released (e.g., through 2014 for the first compliance period). This clarification will assist compliance entities in planning a reasonable and achievable schedule for attaining precisely enough compliance instruments to meet its needs for each compliance period. (SCE1)

Response: We have provided the requested clarification by changing "the year during which" to "the year for which."

E-92. Comment: The regulation should include an appeal process to address technical reporting issues affecting the timely surrender of compliance instruments. Section 95856 outlines the provisions for the surrender of compliance instruments, including data review and determination of a covered entity's triennial obligation and final retirement of the compliance instruments by the ARB Executive Officer. It is unclear if and when a covered entity may appeal the Executive Officer's final determination of a compliance obligation. It is possible that there may be technical differences of opinion between the covered entity and the verifier as to the calculation of emissions that are subject to a compliance obligation. LADWP recommends that an additional subparagraph be added to this section. Modify section 95856 as follows:

<u>(h) Appeal Process.</u>

<u>(1) The covered entity may appeal its triennial compliance obligation within 15 days of receiving the final determination.</u>

<u>(2) An appeal must be submitted in writing to the Executive Officer and must include a detailed explanation of what is being contested. Additional new information may be submitted in support of the appeal.</u>

<u>(3) The covered entity must surrender compliance instruments equivalent to the emissions not subject to the appeal, and hold the balance of compliance instruments in its compliance account to cover the remaining emissions as identified in the Executive Officer's final determination while the appeal is reviewed.</u>

<u>(4) Upon final review and resolution, a written notification shall be sent to the covered entity that includes any findings of the Executive Officer in response to the appeal as well as any necessary adjustments to the covered entity's final triennial compliance obligation.</u>

<u>(5) The Executive Officer shall retire the compliance instruments in the compliance account equivalent to the emissions identified in the written notification. Any remaining allowances deemed not subject to a surrender obligation shall remain in the compliance account for future surrender obligations.</u> (LADWP1)

Response: We have considered whether to include an appeals process for the cap-and-trade regulation. We have concluded that it is not appropriate to specify such a process in the regulation. The MRR contains a provision for a dispute resolution between reporting entities and their verifiers. The results of the verified emissions data reports support the calculation of the compliance obligation. The cap-and-trade rule will rely on the data collected from MRR to determine the compliance obligations for entities.

E-93. (multiple comments)
Comment: The Utilities are unclear as to the process where, accidentally or due to circumstances varying from forecasts, a compliance entity transfers more compliance instruments into its compliance account than are required to meet a compliance obligation (as opposed to the process for "excess emissions" which is clearly defined in section 95857). Subsection 95831(a)(4) states that once a compliance instrument is transferred into the compliance account it may not be removed by the covered entity, and section 95856 states that compliance instruments transferred into the compliance account will automatically be retired at the appropriate surrender date. The Utilities request clarifying language to be included in section 95856 articulating a process for truing up excess compliance instruments. Compliance instruments in excess of the surrender obligation could be transferred by an account administrator back into the covered entity's holding account, or alternatively, held in the covered entity's compliance account until the next surrender deadline. The Utilities request clarification that CARB would not retire any compliance instruments in excess of the surrender obligation unless specifically requested by the covered entity. (MID1)

Comment: The Utilities are seeking clarification regarding treatment of excess compliance instruments in a compliance account that exceed the entity's surrender obligation. Modify section 95856(g) as follows:

(g) When the Executive Officer has determined the covered entity has met its surrender obligations, the Executive Officer shall:

> (1) Retire the compliance instruments surrendered, provided, however, in the event the number of compliance instruments contained in a compliance account at the end of the compliance period exceeds the entity's surrender obligation, the Executive Officer shall retain the excess instruments in the compliance account unless the entity requests the excess instruments be retired or returned to the entity's holding account; and (MID1)
>
> **Response:** We do not believe the recommended changes are necessary. The compliance obligation is based on the reported and verified emissions for which there is a compliance obligation. To meet a surrender obligation, an entity must provide enough compliance instruments to equal its compliance obligation into its compliance account. The Executive Officer will not retire any compliance instruments in excess of the compliance obligation from the compliance account of an entity. It is necessary to restrict the movement of compliance instruments from the compliance account to appropriately apply the market rules designed for the program.

E-94. Comment: As written, a significant percentage of allowances will be unavailable for trading in closing months of a compliance period due to the compliance accounts, holding limits and annual surrender. In the months preceding final true-up, compliance entities will be aware of the fact that they must hold enough of the proper vintage allowances in order to meet their final true-up (for this first compliance period, this will mean vintages 2012, 2013 and 2014). This will cause many compliance entities to conservatively bank the proper vintages, leading to little allowance availability, greatly reduced liquidity and a potential crisis in market confidence during the 2015 true-up period. These problems could be exacerbated by non-compliance entities that bank and carry-over allowances. During this time, compliance entities will have in hand 2015 vintage allowances, allocated early in 2015. Unfortunately, the regulation as written prohibits use of these allowances for use in 2015 true-up for the 2012-2014 compliance period. In order to increase allowance availability, liquidity and market confidence, the regulation should prohibit non-compliance entities from carrying allowances across compliance periods and should allow use of vintages that correspond to the year in which the surrender must be made, as well as earlier vintages. Modify section 95856(b)(2) as follows:

(2) To fulfill any compliance obligation, a compliance instrument must be issued from an allowance budget year within or before the year during which the compliance obligation is <u>to be surrendered</u> ~~calculated~~. (BP)

> **Response:** We disagree with this specific suggestion, which would effectively allow borrowing. We believe borrowing should not be allowed, except for any allowances purchased from the Allowance Price Containment Reserve. We further disagree that we should allow compliance entities to carry forward allowances from one compliance period to the next but prohibit non-compliance entities from doing so. This would run counter to our stated goals to promote a broad and liquid market for compliance instruments.

E-95. Comment: ARB should amend its rules to be consistent with the three-year compliance period. PG&E supports ARB's choice of a three-year compliance period, and requests that ARB clarify the proposed regulation as necessary to ensure that ARB's intention is achieved. As currently written, section 95856(b)(2) appears to require that each ton of emissions be covered by an allowance from the same or a prior budget year, so that higher emissions during a dry 2012 could not be covered by 2013-vintage allowances. Modify section 95856(b)(2) as follows:

(b)(2) To fulfill any compliance obligation, a compliance instrument must be issued from an allowance budget year within or before the ~~year~~ <u>three-year compliance period</u> for which the compliance obligation is calculated." (PGE1)

> **Response:** We disagree. The suggested change would allow entities to meet their annual compliance obligations with allowances from a future vintage year. For example, this comment's suggestion would allow 2014 vintage allowances to meet a 2013 annual compliance obligation. We want to prevent this form of borrowing and ensure the environmental integrity of the program in later years.

Untimely Surrender Obligation

E-96. Comment: Section 95857(d)(2)(A) states that when the covered entity meets its obligations pursuant to subsection (c) "Recovery of Untimely Surrender Obligations", the Executive Officer shall transfer three-fourths of the allowances to the highest-priced tier of the Allowance Price Containment Reserve Account. As discussed earlier in these comments transferring allowances into the Price Containment Reserve Account will remove those allowances from the first market the auction and may inadvertently and unnecessarily tighten the cap. Modify section 95857(d)(2)(A) as follows:

> (A) Three fourths to the highest-priced tier of the Allowance Auction Holding Account ~~Price Containment Reserve Account~~; and
> (B) One fourth to the Retirement Account." (SEMPRA1)

Response: We agree and modified the regulation as suggested.

E-97. Comment: In sections 95820 and 95821, there are references to the "quantitative usage limit set forth in section 95995." SMUD believes that there is a technical error in this reference and that the text should refer to" the quantitative usage limit set forth in section ~~95995~~95854." (SMUD1)

Response: We agree and corrected both sections.

E-98. (multiple comments)
Comment: Covered entities should be allowed to use offsets to cover the standard obligation portion of their excess emissions obligation. Section 95857 lays out the requirements for surrendering additional allowances upon a shortfall in meeting an Annual or Triennial Compliance obligation**.** SMUD understands that the untimely surrender obligation is essentially four times the timely surrender obligation, and that the regulation states as written that the untimely surrender obligation must be met with allowances, not offset credits. SMUD believes that this is unfair, and suggests that the portion of that untimely surrender obligation that would be required for timely surrender be allowed to be met with offsets. Modify section 95857(b)(3) as follows:

(b)(3) Three quarters of a~~A~~ covered entity's compliance obligation for untimely surrender may only be filled with CA GHG allowances or allowances issued pursuant to subarticle 12. One quarter of a covered entity's compliance obligation for untimely surrender may be filled with any compliance instruments eligible under subarticle 4, subject to the quantitative usage limit established in section 95854. (SMUD1)

Comment: Section 95857(b)(3) (p. A-72) provides that a covered entity may surrender allowances but not offsets to fulfill an untimely surrender obligation. The ISOR states (p. IX-51) that this is to ensure the obligation "results in further environmental improvement." However, the strict criteria for offsets will ensure that offsets, being "additional," also lead to environmental improvement. Thus, there should be no prohibition on using offsets to satisfy the untimely surrender compliance obligation, and section 95857(b)(3) should be deleted. (SCPPA1)

Comment: Offsets should be eligible for use in paying a penalty. Under the proposed regulations, offsets cannot be turned in as part of the compliance instrument penalty paid by a covered entity that misses a compliance deadline. The entity must turn in four allowances for each compliance instrument outstanding. The ineligibility of offsets in this context will further devalue offsets relative to allowances. CERP asks ARB to consider allowing covered entities to turn in offsets for at least some portion of a penalty obligation. (CERP1)

> **Response:** We agree with this comment and modified the regulation accordingly.

E-99. Comment: The Sanitation Districts recommend that offsets be allowed to cover an entity's compliance obligations in situations of excess emission, in addition to allowances. Such a restriction on the use of offsets is extremely punitive for the entity with a compliance obligation and is another barrier against creating offsets. (LASD1)

> **Response:** We believe we have removed the perceived “extremely punitive” restriction against offsets by other means. We modified the regulation to allow the use of offsets if that can be done without violating the offset usage limit. Allowances surrendered to meet three-quarters of the obligation will now be placed into the Allowance Holding Account instead of in the Price Containment Reserve Account.

E-100. Comment: Section 95857(c)(4) (p. A-73) provides that an entity has 30 days to secure allowances needed to cover its untimely surrender obligation. This period may or may not include an allowance auction. If there were no allowance auction in this period, the entity may find it difficult to obtain enough compliance instruments. We request that ARB modify this section to give the entity 30 days or, if later, five business days after the next allowance auction to obtain the needed compliance instruments. Modify section 95857(c)(4) as follows:

(4) If the Executive Officer is unable to retrieve sufficient allowances using the above process, the Executive Officer shall provide the deficient covered entity 30 days <u>or, if later, five business days after the next auction to</u> secure the <u>compliance instruments</u>~~allowances~~ needed to cover its untimely surrender obligation; (SCPPA1)

> **Response:** We agree and made changes similar to those suggested by the commenter. The entity now has five days past the next auction or reserve sale, whichever is later.

E-101. Comment: Section 95857(c)(5) (p. A-73) provides that if an entity does not fulfill its compliance obligation for untimely surrender, the Executive Officer will take allowances from the holding accounts of affiliates to which the defaulting entity has transferred allowances. The ISOR states (at IX-52) that this provision is intended to address situations in which an entity takes steps to shield compliance instruments from retirement. However, under the current drafting this provision may have adverse consequences for innocent “affiliates” who purchased allowances from the defaulting entity in good faith. This provision should be carefully limited to avoid harming such entities. Various limitations should be considered, such as restricting the provision to transfers of allowances made without reasonable compensation and transfers to entities that have reason to believe the transferring entity may default on its compliance obligations. Section 95857(c)(5) is especially onerous insofar as “affiliates” is not defined. The Executive Director could construe the term to reach as broadly as “direct and indirect corporate associations.” A definition of “affiliates” is required. The definition should not be too broad, given the possibility of adverse consequences for innocent entities. (SCPPA1)

> **Response:** This suggested definition is no longer necessary because section 95857(c)(5) has been removed from the regulation.

E-102. (multiple comments)
Comment: Section 95857(d)(2)(A) (p. A-74) provides that three-quarters of the allowances used to fulfill an untimely surrender obligation will be transferred to the highest-priced tier of the Allowance Price Containment Reserve Account (Reserve). The ISOR states (at IX-54) that this provision is to ensure that fulfilling the untimely surrender compliance obligation does not overly reduce the supply of compliance instruments and consequently raise their price. However, there is no specific rationale for putting the allowances in the highest tier of the reserve. If allowances are placed in the highest tier, they will be withdrawn from the market at market prices and will only be available at a price that is calculated to be significantly higher price that may never be reached. SCPPA opposes having tiers in the Allowance Price Containment Reserve Account. However, if the allowance reserve must contain tiers, instruments added to the reserve should be added not to the highest tier but to the lowest-priced tier that has not yet been exhausted and closed. (SCPPA1)

Comment: The Utilities request that allowances surrendered for excess emissions destined for the allowance price containment reserve be allocated to the lowest tier within the reserve. Focusing the allowance on the highest tier only serves to penalize the other covered entities that must purchase from the reserve, the majority of which have not had an excess emissions occurrence. Alternatively, putting these allowances into the lowest tier provides covered entities with an ability to purchase these allowances without unduly increasing the cost burden and the covered entity’s avoided costs are more likely to be spent on AB 32 reduction activities. In contrast, the revenue from allowances bought at the reserve is directed to the State’s General Fund, and there is no guarantee that these monies will be spent on AB 32 reducing activities. Modify section 95857(d)(2)(A) as follows:

(A) Three fourths to the ~~highest~~ lowest priced tier of the Allowance Price Containment Reserve Account. (MID1)

Comment: Similarly, excess emissions penalty allowances that are surrendered pursuant to 95857(c) should not be automatically transferred to the Allowance Price Containment Reserve Holding Account. That portion of the allowances required to be surrendered pursuant to 95857 (c), that are in excess of the actual emissions obligation of the covered entity, specifically the three penalty allowances required to be turned over as a penalty should be deposited into the Auction Holding Account rather than the Allowance Price Containment Reserve Account as specified in 95831 (c)(4)(C) and 95857 (d)(2)(A). The placement of these allowances in the reserve account unfairly penalizes the rest of the market, by requiring the three allowances to be removed from circulation and placed at a minimum price level of $50 per ton. There is no other purpose to place these allowances at the highest allowance price containment reserve account other than to penalize other market participants. To do otherwise acts to arbitrarily and unreasonably force the overall market price to a higher level. (SMUD)

> **Response:** We modified the regulation such that three-quarters of allowances used to fulfill an untimely surrender obligation will be transferred to the Auction Holding Account. Therefore, these comments regarding which tier to place allowances are no longer relevant.

E-103. Comment: Section 95857(a)(2) states that the compliance obligation for untimely surrender ("excess emissions") will not apply if the instruments transferred to meet the obligation were rendered invalid because of the reversal of an offset credit. In that case, the entity is given 30 days after the notice of reversal is received to make up the excess emissions. This, in effect, allows a facility to purchase dubious offsets or even those known to be likely found to be invalid, in order to delay or avoid the penalty for untimely surrender of compliance instruments. This provision also compromises the point at which the penalty provisions, which state that each day after a required instrument is not timely submitted is a separate day of violation, are triggered. Is it when the instrument was originally due? When it is determined to be invalid? When any rights to appeal that determination are exhausted? (CAPCOA1)

> **Response:** Section 95857 has been modified to only apply in the case of invalidation, not a reversal, and the entity is given 90 days to replace the invalidated offset with another compliance instrument. We believe the risk of invalidation is small, as the offset program has been designed with a system of checks and balances and will be under our direct oversight. All provisions related to invalidation determinations and notifications are in section 95985. The additional time is provided to allow the entity access to an auction or Reserve sale to acquire “replacement” compliance instruments. We do not believe an entity will buy suspect offsets to gain additional time, only to go back out to the market to buy additional compliance instruments to cover the same compliance obligation.

E-104. Comment: Section 95857(c)(1) states that the obligation to surrender allowances for excess emissions is "immediately due." But, there is no mention of the triggering date. Is it the date the report for that compliance period is submitted? Is it as of the date that an audit is complete? Is it the date that CARB issues its final determination? For penalty purposes, this date is critical. (CAPCOA1, CAPCOA2)

> **Response:** This comment is no longer relevant because section 95857(c) was modified, and the requirements for when the "excess emissions" are due was clarified in section 95857(b)(6).

E-105. Comment: The Utilities greatly appreciate CARB's inclusion of a time period within which covered entities may resolve excess emissions issues. However, there is no opportunity for a covered entity to purchase the required allowances to fulfill the excess emissions requirement at either auction or the reserve following the November 1 surrender deadline. The same argument applies to the proposed annual surrender deadline of May 15 for facilities (please note that the Utilities recommend changing the annual surrender deadlines to November 1 for both operators and suppliers and electric power entities above). Thus, the Utilities would recommend the cure period be extended to 100 days to provide an opportunity for covered entities to access the auction. Modify section 95857 as follows:

(c) Allocation to Public Utilities.

(4) If the Executive Officer is unable to retrieve sufficient allowances using the above process, the Executive Officer shall provide the deficient covered entity ~~30~~ 100 days to secure the allowances needed to cover its untimely surrender obligation. (MID1)

> **Response:** Section 95857(b)(4) was modified to state that "the untimely surrender obligation is due within five days of the first auction or reserve sale conducted by ARB following the applicable surrender date, whichever is the latter, and for which the registration deadline has not passed when the untimely surrender obligation is assessed."

E-106. Comment: The Utilities continue to have concerns regarding the effect of imposing a penalty that would require the submission of multiple allowances for each excess emission. This approach appears to be counterproductive, setting the covered entities and the AB 32 cap and trade program up for failure. While the Utilities appreciate that the additional allowances will be available to covered entities through the reserve if needed for compliance obligations, the exclusion of using offsets to meet this penalty will essentially have the effect of penalizing the covered entities by constraining the future of the market. Modify section 95857(b) as follows:

(b)(2) The covered entity's compliance obligation for untimely surrender is calculated as ~~four~~ two times the entity's excess emissions; and.

(b)(3) The covered entity's compliance obligation for untimely surrender may only be fulfilled with CA GHG allowances of allowances issued pursuant to subarticle 12.

Offsets shall be allowed to cover excess emissions by deduction from the covered source's compliance account equal to three times the number of the source's emissions (3x the allowances shortage). (MID1)

> **Response:** We disagree with this comment. We modified the regulation to make three-fourths of compliance instruments available through auction. After careful internal deliberation and consultation with outside experts and our WCI Partner jurisdictions, we remain convinced that the calculation for an entity's compliance obligation is appropriate and should be met with allowances and offsets for one-fourth if using the offsets does not violate the quantitative usage limit. We believe that our chosen multiplier of four achieves a balance between providing a strong incentive for timely compliance and not imposing unduly harsh obligations for lack of timely compliance.

Three-Year Compliance Period

E-107. Comment: LADWP strongly supports policies that have been incorporated into the proposed regulation intended to help contain compliance costs, including three year compliance periods. (LADWP1)

> **Response:** Thank you for the support.

E-108. Comment: We would have preferred annual compliance periods but the fact that annual reporting is still required of all participants helps to mitigate these concerns. (SANDBAGCC)

> **Response:** No response necessary.

Recordkeeping and Reporting

E-109. (multiple comments)
Comment: Section 95850(b) requires records associated with this proposed regulation be retained for 10 years. The corresponding requirement in the California GHG reporting rule (section 95105(a)) is five years. Since this rule is significantly linked to the California GHG Mandatory Reporting Regulation the record retention periods should be consistent. We recommend only a five-year records retention period, since this should provide ample time period for CARB to review, if needed, a covered entity's records. (PRAXAIR)

Comment: Section 95850(b) (p. A-60) requires covered entities to retain records for at least 10 years. This period is unreasonably long. By contrast, section 98.3(g) of the US Environmental Protection Agency's Mandatory Reporting of Greenhouse Gases Rule, 40 CFR Part 98 (EPA Rule), only requires records to be kept for three years. As ARB is aiming to harmonize with as many of the provisions of the EPA Rule as possible, as discussed in the ISOR for the revised MRR, a record retention period similar to that of the EPA Rule should be considered. Records should be retained until the end of the compliance period following the compliance period in which the record was generated.

As a result, records would be held from three to six years, depending upon the point in a compliance period at which a record was developed. Modify section 95850(b) as follows:

(b) Record Retention Requirements. Each covered entity must retain all of the following records <u>until the end of the compliance period following the compliance period in which the records were generated</u> ~~for at least 10 consecutive years~~ and must provide such records within 20 calendar days of receiving a written request from the Executive Office. (SCPPA1)

Comment: In light of what appears to be a de facto standard of five years among Federal Regulatory agencies with similar responsibilities, the ten year standard proposed by CARB would be an outlier. Therefore, in order to minimize unnecessary compliance costs for market participants, CARB should adopt a five-year record retention standard, rather than the proposed ten. (MSCG2)

> **Response:** We modified both rules to require record retention for 10 years. This allows records to be retained over at least two compliance periods, to support several program design elements, such as under-reporting in section 95857.

E-110. Comment: The Utilities believe it is important to allow flexibility for circumstances whereby the covered entity may require more than 20 calendar days to compile all of the records being requested. Such flexibility is provided under similar requirements in the California Public Records Act (Government Code section 6250 et seq.). We suggest giving the Executive Officer the ability to extend the time for providing documents in appropriate circumstances. Modify section 95850 as follows:

(c) <u>In unusual circumstances, the time limit for providing records prescribed in this section may be extended by the Executive Officer, upon written request by the covered entity setting forth the reasons for the extension and the date on which the documents are expected to be dispatched. As used in this section, "unusual circumstances" means the following, but only to the extent reasonably necessary to the proper processing of the particular request:</u>

> <u>(1) The need to search for and collect the requested records from field facilities or other establishments that are separate from the office processing the request.</u>
> <u>(2) The need to search for, collect, and appropriately examine a voluminous amount of separate and distinct records that are demanded in a single request.</u>
> <u>(3) The need for consultation, which shall be conducted with all practicable speed, with another agency having substantial interest in the determination of the request or among two or more components of the agency having substantial subject matter interest therein.</u>
> <u>(4) The need to compile data, to write programming language or a computer program, or to construct a computer report to extract data.</u> (MID1)

> **Response:** We do not agree. This type of time provision for responses to data and information requests is standard practice for ARB regulations. It is clear in

the regulation which types of data are to be retained under this provision. It would not be unreasonable for entities to have a central repository of this specified information for ease of access.

Increase Transparency

E-111. (multiple comments)
Comment: The public should have access to the type and amount of compliance instruments surrendered by each entity each time the entity surrenders compliance instruments for compliance. There should be sufficient information that is publically available in a timely fashion to allow the public to review and check compliance, while keeping price and trade secrets confidential. (LUDLOW, UCS1)

Comment: As enforcement progresses, increase transparency. (UCS2, CADMANS)

Response: We recognize the need for transparency, and plan to enable the public to readily review and check compliance while ensuring proper confidentiality of business information. However, we believe that this is an implementation issue and details will be developed during the implementation process.

E-112. Comment: The public should have access to the type and amount of compliance instruments surrendered by each entity each time the entity surrenders compliance instruments for compliance. There should be sufficient information that is publically available in a timely fashion to allow the public to review and check compliance, while keeping price and trade secrets confidential. (WALTERS)

Response: The proposed regulation provides that the serial numbers of retired compliance instruments will be recorded to a publicly available Permanent Retirement Registry (section 95831(b)(3)(C)). Additional details about which types of information will be made publicly available will be part of program implementation.

E-113. Comment: It is essential that emissions data is made publicly available on an annual basis as soon as possible to enable timely scrutiny of the participants' behavior in the scheme. (SANDBAGCC)

Response: Thank you for your comment. ARB currently makes reported GHG emissions data reports publicly available each year once the reports have been received and verified.

E-114. Comment: While the proposed transportation fuels applicability in section 95852(d) could be read to include domestic production, we suggest making this more explicit, similar to language for natural gas in sections 95852(c) and (e). The following revision would help avoid any potential misunderstanding or attempt to avoid compliance. Modify section 95852(d) as follows:

(d) Suppliers of RBOB and Distillate Fuel Oils. A supplier of petroleum products covered under section 95811(d) or 95812(d) has a compliance obligation ~~from~~ for every metric ton CO_2e of GHG emissions that would result from full combustion or oxidation of the quantities of the following fuels that are imported and/or delivered to California, produced in California, or otherwise delivered to end users in California. (ICCT1)

Response: The applicable coverage of fuels is intended to include fuel produced in California. The new language in 95852(d) clarifies this point.

E-115. Comment: Most of the detail of the approach for attributing emissions to imported power is laid out in the proposed "Amendments to the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions" rather than the cap and trade regulation. WPTF has provided ARB its specific concerns and recommendations in a separate submission on the proposed reporting regulation, where we have also requested technical modifications to the regulation regarding the attribution of imports. We therefore recommend in this proceeding that ARB incorporate the technical changes to the reporting regulation that WPTF has recommended, and that once completed, the definition of "Specified Source of electricity" in the cap and trade regulation should be modified so that it is consistent with the final technical regulation. (WPTF)

Response: The definition of "specified source of electricity" was modified in both the first and second 15-day changes to the regulation. We have coordinated changes between the MRR and the cap-and-trade regulation.

E-116. Comment: We support the proposed 15-day changes to ensure that emissions from livestock and manure are not in the mandatory reporting or in the program as well as the portable engines, the diesel pump engines. We certainly encourage you to ensure that those 15-day changes are included. (CCASSOC)

Response: Thank you for the support.

F. CO-POLLUTANTS

This section includes comments and responses about the Co-Pollutant Emissions Assessment (Appendix P of the Staff Report). Major sub-topics include concerns about potential increases in criteria air pollutants and toxic air contaminants, the potential effects on communities already affected by co-pollutants and the need to develop a methodology to identify these communities, the fulfillment of AB 32 requirements concerning co-pollutants and affected communities, the need for a health impact assessment, the scenarios used in evaluating the potential effects on California communities, and monitoring of the program's impact on co-pollutant emissions.

F-1. (multiple comments)
Comment: Fresno suffers from both extremely high poverty rates and extremely bad air, and severe health problems, such as high asthma rates, due to these problems. We are concerned that pollution trading could result in increased local pollution of criteria pollutants. The communities we work with, the disadvantaged and most vulnerable populations, are very concerned with increasing pollution and the cumulative impacts of multiple sources in their small communities. (FRESNOMINISTRY)

Comment: We are asking you to consider the localized impacts so that we are not just blending all other kinds of sources of emissions with the emissions that are impacting low income communities. (CANAACP)

Comment: The current project allows harms to California, for instance, by allowing increasing industrial pollution in heavily industrialized California communities, and by causing evictions of indigenous people through fake forest offset projects. (CBE1)

Comment: Cap and trade schemes also exacerbate environmental injustice by increasing hotspots, creating price volatility, and leading to oppression through high risk and fraudulent offset projects that too often also result in displacement. The proposed regulation does nothing to avoid the known pitfalls inherent to cap and trade. Instead, the regulations bend over backwards to accommodate polluters' desire for zero cost compliance, ease and flexibility at the expense of true significant reductions, health protection (avoiding increases in other pollution), and environmental justice. (CBE1)

Comment: Under the proposed regulation, emitters could just as easily choose not to reduce any GHG emissions at all by simply buying credits and offsets. This would result in the equally disproportionate outcome that low income communities of color around the entities would see absolutely no direct or co-benefits from this cap and trade regulation. Industrial polluters in California are predominantly located and tend to cluster in low income neighborhoods and communities of color. A demographic analysis of the communities nearest industrial facilities in California reveals that people of color comprise 58 percent of the population living within one mile of a facility, and 62 percent of the population living between one to six miles from a facility. The area within six miles of a facility is densely populated, reaching over 5,000 people per square mile. The demography of populations over six miles away from a facility changes dramatically. People of color comprise only 46 percent of the population and the density drops to 125 people per square mile. Children of color comprise between 71-74 percent of children living within 6 miles of a facility and 57 percent of those living more than six miles away. Allowing offsets and credits for these entities means these communities will see no benefits from this regulation. ARB should not allow trading, especially in overburdened communities. The unrestricted trading, reserve credits, and large percentage of offsets allowed in this regulation seriously threatens to further overburden such communities, in violation of AB 32. (CRPE1)

Comment: ARB should make good on the commitment made to disadvantaged communities in AB 32, namely to ensure that activities undertaken to comply with the regulation do not disproportionately impact low-income communities. (CIPAL)

Comment: We have an overall concern about the staff proposal for the program which we believe leans heavily towards benefiting pollution sources economically, while leaning minimally towards either economic or health benefits for the most impacted and disadvantaged communities. For example, the staff proposal to move the offsets limits from four percent of emissions (as proposed in the Scoping Plan, December 2008) to now proposing eight percent of emissions allows polluting sources to achieve the majority of their respective share of emission reductions by purchasing offsets (nearly 100 percent). Clearly, this level of offsets will have a negative health impact on the ability to maximize localized pollution reductions that should benefit California residents. This will be true of the program as it is implemented within the State, and particularly acute once California begins linking our program with other states and nations, as is anticipated. (CCA1, CCA3)

Comment: A scheme that is flexible for polluters tends to dilute the environmental goal, and exacerbate social injustices. Although the proposed regulation states that CARB will monitor the consequences of the cap and trade program in relation to co-pollutants, the provisions offered are inadequate. This is a fundamental problem: the basis of the system is that the market chases after the cheapest abatements, and under such a scheme there is no recourse to adjust for the concentration of pollutants in “hot spots”, potentially exacerbating environmental racism. “We note with particular concern the treatment of biofuels, which appear at the cheaper end of the carbon abatement curve for California.” (CTW)

Comment: Needed co-pollutant reductions do not address Environmental Justice issues. Any area with one refinery in it is impacted by a major pollution source. One example of extreme Environmental Injustice impacts due to the oil industry, with the very highest concentration of oil refineries in the state, is the Wilmington/Carson area in Southern California which contains about a third the state’s refining capacity. This area includes about half of Los Angeles’ refining capacity (five refineries and about 650,000 bpd). In the Los Angeles region overall, refineries dominate the top 15 VOC emitters, out of many hundreds of Stationary Sources listed by SCAQMD in the 2007 Air Quality Management Plan. The Wilmington Area includes about half the refinery VOCs emissions (about 1,600 out of 3,200 tons per year) in the LA region. A plume map provided by SCAQMD graphically displays that Wilmington receives the air pollution from five overlapping refining plumes (isopleths) generated over this area (two ConocoPhillips refineries, Valero, BP, and Tesoro).

Wilmington has demographics that demonstrate that people of color and low income people are bearing the brunt of the heavy industry concentration in this area.

As if this extreme concentration of oil refineries was not enough to warrant local cleanup efforts, this area also includes oil drilling operations (Wilmington is the third largest oil field in the U.S.), extreme heavy diesel truck traffic (as a major goods movement corridor), the biggest Ports in the Country (Ports of LA and Long Beach which are the biggest single pollution sources in the area), and hundreds of other industrial sources. Clearly, refining areas are in need of direct, local pollution controls, not the potential for further concentration and expansions that the Cap and Trade proposal makes likely, through allowing refineries to buy their way out of local pollution control. (CBE1)

Response: The commenters are concerned that a greenhouse gas emission cap-and-trade program would (1) lead to localized increases in criteria and toxic air pollutant emissions, otherwise known as co-pollutants, and (2) that these increases could exacerbate existing inequities in impacted and disadvantaged communities; particularly low-income and minority communities. The commenters attribute this to a facility's ability to purchase allowances or a limited number of offset credits in lieu of reducing greenhouse gas emissions on site.

As stated in the Emissions Assessment, we believe that overall co-pollutant emissions in California would likely decrease as a result a cap-and-trade program. Nevertheless, during the regulatory development process, we evaluated the potential for localized increases in co-pollutant emissions in affected communities due to a cap-and-trade program to the best of our ability. The findings of this analysis can be found in the Staff Report and its Appendix P: Co-Pollutant Emissions Assessment. Since the distribution of changes in co-pollutant emissions resulting from the cap-and-trade program are dependent on how individual facilities choose to comply with the program, we evaluated how co-pollutant emissions could change in three hypothetical scenarios within four environmental justice communities—Wilmington, Oildale/Bakersfield, Richmond, and Apple Valley/Oro Grande. Under the three hypothetical scenarios, we found that co-pollutant emissions could increase or decrease a very small amount. However, most compliance approaches are expected to result in a reduction in co-pollutants through increased efficiency and decreased combustion of fossil fuel.

It is important to note that the mere presence of a cap-and-trade program for greenhouse gas emissions will not weaken or reduce facility-specific requirements or permits for co-pollutants. All facilities will continue to be subject to existing State, federal, and local ordinances and rules. A brief discussion of key existing air quality laws that minimize potential adverse impacts is presented below.

The federal Clean Air Act (CAA) of 1970, as amended in 1977 and 1990 (42 USC section 7506(c)), establishes National Ambient Air Quality Standards (NAAQS) for air pollutants that pose a threat to human health and welfare. California has adopted more stringent air quality standards for most of the federal criteria pollutants under the California Clean Air Act (CCAA) of 1988. Similar to the federal standards, the California standards have been designed to protect the health of the most sensitive persons with a margin of safety.

Under the federal Clean Air Act, all states, including California, are required to develop State Implementation Plans (SIPs) that provide for attaining the national ambient air quality standards. The most recent comprehensive SIP was completed in 2007, and a new SIP will be finalized in 2012. The SIP is focused on areas with pollution levels that exceed national air quality standards for ozone and PM2.5. However, most of the control measures adopted pursuant to the SIP will reduce emissions and improve air quality throughout the State.

New Source Review (NSR) is a title applied to programs regulating the new construction of, and/or modifications to, industrial sources that emit, or will emit, air pollutants. NSR requirements under State law are codified in Division 26 of the California Health and Safety Code. Specific to NSR, each local air district is to include in its attainment plan a stationary source control program designed to achieve no net increase in emissions of nonattainment pollutants or their precursors for all new or modified sources that exceed particular emission thresholds. Each of the 35 air districts in California has its own NSR program and issues permits to construct and operate. The permit requirements are dependent on the California AAQS or NAAQS designation (attainment, nonattainment, and unclassifiable areas), and the amount and type of pollutants that the source will emit. In addition, most new and modified stationary sources are required to use Best Available Control Technology (BACT). Furthermore, all the air districts have either a policy or regulation that addresses toxic air pollutants for new and modified sources.

The CEQA review of local projects may identify and require mitigation for mobile and other emission sources. CEQA requires that where a project will have significant impacts, the lead agencies (in this context, cities, counties, and air districts) must consider alternatives (including, where appropriate, alternative locations that would have fewer impacts) and require feasible mitigation to reduce those impacts to less-than-significant levels. Mitigation for a given project could include additional pollution control technologies, off-site measures, and mobile source mitigation that would reduce cumulative pollution in the area affected. Further analysis of what may be appropriate for specific, future energy-related projects must be analyzed in response to a specific proposal.

Facilities whose toxic air contaminant emissions and risk potential exceed a certain threshold must prepare a Health Risk Assessment (HRA) under the “Hot Spots” Information and Assessment Act. More information about the hotspots program is available in the Appendix O. This and other regulations will continue to result in significant reductions in co-pollutant emissions, exposure, and health-based risk.

Moreover, through the Energy Efficiency and Co-benefits Assessment Regulation for Large Stationary Sources, we are currently collecting information on opportunities for further GHG and co-pollutant emission reductions. We are scheduled to receive these data by the end of 2011. We will initiate a process to ensure that large industrial sources subject to the regulation be required to take cost-effective actions to reduce emissions identified under those audits. The audit results, due to ARB by the end of 2011, will inform the development of regulatory requirements that staff intends to propose to the Board in 2012. We plan to initiate a separate public process in fall 2011 to discuss metrics and actions to implement this commitment.

Although we anticipate that co-pollutant emissions would decrease as a result of the implementation of the cap-and-trade regulation, ARB is committed to monitoring the regulation’s implementation to identify and address any situations where the program has caused an increase in criteria air pollutants or toxic emissions. To assist staff in its assessment, we developed an Adaptive Management Plan that was posted for public review on October 10, 2011, and considered and approved by the Board at its October 20, 2011, public hearing. The Board’s approval of the Adaptive Management Plan is reflected in Attachment C of Board Resolution 11-32.

Adaptive management is a process of information gathering, review and analysis, and response that promotes flexible agency decision-making. It is particularly appropriate where complex systems are involved, where the effects of an agency’s decisions and actions play out over an extended period of time, and where the agency must meet multiple objectives—as in the case of the cap-and-trade regulation, which was adopted by the Board at its October 20, 2011, public hearing.

The adaptive management approach will allow us to collect and review applicable data sources (e.g., the MRR data, market tracking system, economic data, emission inventory, air monitoring data, and energy efficiency and co-benefits audits) and develop the appropriate tools to determine if there are impacts due to compliance with the cap-and-trade regulation as information becomes available. We will work with other State agencies and local air districts during this process. If it is determined that an adverse impact has been identified as result of the regulation, ARB will conduct a public process and report to the Board on appropriate responses.

Adaptive management is consistent with ARB's long-standing approach to program implementation, which incorporates ongoing evaluation of how programs and regulations are implemented on the ground, regular updates to the Board, and adjustments to program implementation and regulatory requirements, as necessary.

A separate but related concern raised by several commenters is that a greenhouse gas emission trading program could increase existing inequities related to the burden of air pollution exposure; that is, that low-income and minority communities would bear a disproportionate share of the impact of unforeseen increases in air pollution, and/or would experience less of the benefits from a cap-and-trade program.

Data and research clearly indicate that a disproportionate share of facilities with high GHG emissions are located in low-income communities with a high percentage of minorities, and that the annual co-pollutant emissions burden from large GHG-emitting facilities is larger for minorities. However, this is entirely different than finding that facilities located in minority neighborhoods are more likely to buy allowances or offsets instead of reducing greenhouse gas emissions on site.

Counter to the commenters' contentions, numerous studies have evaluated the potential for inequitable impacts from emissions trading programs on minorities and found that trading did not have a disproportionate impact.

As noted by the Market Advisory Committee:

> "U.S. Environmental Protection Agency staff analysis found that under the SO_2 emission trading program, the largest reductions occurred in areas with the highest emission levels. This finding was true both regionally and at individual plants."[1]

Thus, it is possible that the areas with highest emissions could experience relatively greater benefits from a cap-and-trade program.

The most effective way to reduce the impacts of co-pollution emissions in low-income and disadvantaged communities is to implement programs that target reductions in co-pollutant emissions directly. While a GHG-focused program would likely reduce co-pollutant emissions along with GHG emissions, it is not the most effective mechanism for decreasing exposure to co-pollutants.

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[1] See Market Advisory Committee to the California Air Resources Board, Recommendations for Designing a Greenhouse Gas Cap and Trade System for California (hereafter "MAC Recommendations") at 10 (2007) [citing The Acid Rain Program and Environmental Justice: Staff Analysis" (September 2005) U.S. Environmental Protection Agency, Office of Air and Radiation, Clean Air Markets Program].

A separate commenter referred to the potential inclusion of REDD forest credits when they referred to "fake forest offset projects." The regulation does not allow any REDD credits into the cap-and-trade program. If the Board were to include REDD offsets at a future date, it would only occur through an amendment to the cap-and-trade regulation. This would trigger a required CEQA analysis and full public process before the Board would take action. As these credits are not part of the current rule, this concern is not applicable.

Another commenter raised concerns about the use of treatment of biofuel. The regulation exempts certain types of biofuels from a compliance obligation if they meet the requirements for reporting, verification, and eligibility under the MRR and cap-and-trade regulation. The intent of the cap-and-trade regulation is to reduce GHGs associated with fossil fuels. In that context, the use of biofuels is a preferred path. There are several constraints related to location, collection, and transportation of biofuels that limit their opportunity for use by the types of facilities under the cap. Every capped facility will have to decide for itself the most cost-effective way to reduce its emissions. Within each facility, there may be opportunities for retrofits or upgrades that could reduce emissions much more cost-effectively over the life of the program than just switching from fossil fuels to biofuels. We believe the program is designed to achieve its objective of reducing GHG emissions from the use of fossil fuels in a cost-effective manner.

F-2. (multiple comments)
Comment: ARB has not adopted a method to identify environmental justice communities. ARB has not adopted a methodology for identifying disproportionately impacted, low-income communities throughout the state. For the co-pollutant assessment, ARB chose four communities after consulting with the Environmental Justice Advisory Committee and other environmental stakeholders. While we agree these communities are environmental justice communities that should be assessed, ARB can't stop there. Each environmental justice community is unique and ARB needs to have a method to identify and analyze these communities. Without a screening method, it is impossible for ARB to evaluate whether this regulation, or any other under AB 32, will have localized impacts in communities already adversely impacted by pollution. ARB needs a screening method to ensure a complete evaluation of the most vulnerable communities, the communities the Legislature sought to protect when it adopted Health & Safety Code section 38652(b)(1). A host of factors, such as race, linguistic isolation, and the number of polluting sources pre-existing in an area, along with income should be used to paint a more complete picture. The Board should adopt the mapping tool created by Manuel Pastor, James Sadd, and Rachel Morello-Frosch which was part of the ARB-funded project to develop methodological approaches to address environmental justice concerns and apply the Environmental Justice Screening Method statewide before making decisions on market-based mechanisms, including this cap and trade regulation. (CRPE1)

Comment: I wanted to touch on two issues, both having to do with the proposed 15-day modifications—or the resolution with the proposed 15-day modifications.

First deals with the finding that the cap and trade regulation is consistent with ARB's environmental justice policies and will equally benefit residents of any race, culture, or income level. That's contradicted a little bit later on in the resolution where it finds that because of the flexibility imbedded in the cap and trade program, it's difficult to pinpoint where reductions will happen and where there might be increases in criteria pollutants or toxic contaminants. And because of the siting of many of the industries under the cap, they are disproportionately sited in low income communities and communities of color.

So one of the things that the Environmental Justice Advisory Committee and several environmental justice groups have been talking about for a long time has been being clear about where localized pollution increases are happening and being sophisticated with that analysis.

And I think one of the issues that has been raised several times is where health impacts are happening due to the cap and trade regulation. And the health impact assessment came out just two days before the public comment period was over. And I think that was the opposite of what had been hoped for, were that the health impact assessment would help guide the crafting of the regulation.

I would also add that the way the cap and trade system is structured in terms of localized pollutions is that it will be monitored as the program evolves. And there's some language in here that says that if unanticipated adverse environmental impacts are identified that are substantial enough to interfere with or undermine the achievement of the objectives for the cap and trade program as defined by AB 32, that's a little vague in terms of what will actually trigger changes especially as the program is implemented in the long term because of the need for certainty. So the chances of adjustment down the course without some criteria of what that will be are going to be less likely. (CRPE2)

Comment: CARB should direct staff to work with community stakeholders to develop a process for modifying the methodology for identifying the most impacted communities that utilizes GIS mapping looking at cumulative air emissions combined with multiple socioeconomic factors (including those included in AB 1405). (KUSTIN02, KUSTIN11, KUSTIN12)

Comment: Catholic Charities urges ARB to develop a more robust methodology than it currently has to identify the most impacted communities. ARB should use GIS mapping to look at cumulative air emissions combined with multiple socioeconomic factors. We recommend ARB use the methodology developed specifically for the ARB by Doctors Manuel Pastor, Rachel Morello-French, and James Sadd. (CATHCHAR1)

Comment: We urge ARB to develop a more robust methodology than it currently has to identify the most impacted communities. ARB should use GIS mapping to look at cumulative air emissions combined with multiple socioeconomic factors. In its August 25, 2010 letter, ARB's Environmental Justice Advisory Committee gave specific recommendations on what belongs in a screening method for low-income communities that are highly impacted by air pollution. (CIPAL)

ARB should adopt and utilize the Environmental Justice Screening Method (EJSM) to identify and monitor communities highly impacted by the cumulative emissions. The report states that this is not available on a statewide level, but the academic researcher team stated otherwise to the Environmental Justice Advisory Committee (EJAC) at their June 9, 2010, meeting. The EJAC strongly recommended that CARB utilize the tool to screen for impacted communities throughout the state to meet the requirements and the intent of AB 32. The EJSM may also be used to screen for other categories of impacted communities, whether they are highly impacted or not in order to ensure pollution reductions in communities highly impacted and that no new hot spots are being created, especially in a "medium" impacted community. (CBE1)

Comment: CARB should evaluate communities based on exposure to pollution as well as socioeconomic vulnerability that exacerbate the impacts of pollution. We recommend that ARB use the EJSM in the development of the CBF to adequately screen for eligible communities, but also include the communities that may not be included in the screening due to non-incorporated status. The EJSM should also be updated on a frequent and regular basis to accommodate new and developing research and statewide databases. (CBE1)

> **Response:** The commenters advocate the use of a geographic information system (GIS) mapping tool, specifically the Environmental Justice Screening Method developed by Dr. Manuel Pastor, to identify low-income communities impacted by air pollution for determining impacts from market-based compliance mechanisms.
>
> When selecting the communities (Wilmington, Oildale/Bakersfield, Richmond, and Apple Valley/Oro Grande) for the Cap-and-Trade Emissions Assessment, we used the Environmental Justice (EJ) Screening Method developed by Dr. Pastor, recommendations from the Environmental Justice Advisory Committee (EJAC), and other information. A subset of these communities was also used by the California Department of Public Health (CDPH) in the Health Impact Assessment (HIA). However, when the Emissions Assessment and the HIA were written, the EJ Screening Method was limited to the South Coast, and it could only be used as part of the process of identifying a comprehensive list of affected communities for all of California. Since then, Cal/EPA has financed additional research to expand the EJ Screening Method to the Bay Area and the Central Valley. The research summary will be available in fall 2011. ARB will review this report to determine how best to incorporate it into the overall evaluation of the cap-and-trade program as it is implemented.
>
> It is important to note that even if these findings were currently available, the EJ Screening Method cannot be used to determine the future impacts of a cap-and-trade program or any alternatives. It is composed of retrospective data on air

pollution and socioeconomic indicators, and does not have the capability to evaluate prospective impacts or the underlying causes of air pollution.

Although we anticipate that co-pollutant emissions would decrease as a result of the implementation of the cap-and-trade regulation, ARB is committed to monitoring the regulation's implementation to identify and address any situations where the program has caused an increase in criteria air pollutants or toxic emissions. To assist staff in its assessment, we developed an Adaptive Management Plan that was posted for public review on October 10, 2011, and considered and approved by the Board at its October 20, 2011, public hearing. The Board's approval of the Adaptive Management Plan is reflected in Attachment C of Board Resolution 11-32.

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The adaptive management approach will allow us to collect and review applicable data sources (e.g., the MRR data, market tracking system, economic data, emission inventory, air monitoring data, and energy efficiency and co-benefits audits) and develop the appropriate tools to determine if there are impacts due to compliance with the cap-and-trade regulation as information becomes available. We will work with other State agencies and local air districts during this process. If it is determined that an adverse impact has been identified as result of the regulation, ARB will conduct a public process and report to the Board on appropriate responses.

Adaptive management is consistent with ARB's long-standing approach to program implementation which incorporates ongoing evaluation of how programs and regulations are implemented on the ground, regular updates to the Board, and adjustments to program implementation and regulatory requirements, as necessary.

F-3. (multiple comments)
Comment: The Board should not make a decision on this cap and trade regulation before a Health Impact Assessment (HIA) is completed. The staff report refers to the HIA being conducted by the California Department of Public Health but does not indicate when it will be completed. According to the report, the HIA will evaluate potential health impacts, health disparities among communities, and potential uses of any revenue generated by this proposed regulation. This is all valuable information to have before the Board makes a decision on the cap and trade regulation. Waiting to examine "community health status, air pollution exposures, and vulnerable populations"

as part of the "public decision-making process on the use of revenues generated by the program" is unacceptable and violates the mandates of AB 32. (CRPE1)

Comment: CARB needs to complete and include a health analysis before taking action on the proposed regulation. This assessment would include the existing localized health burdens, the impacts of free allowances, trading, out-of-state offsets, economic impacts and directing investments into the most impacted communities. This analysis is crucial to evaluating the proposed regulation. (CBE1)

Comment: We are very concerned that a comprehensive health impacts assessment (HIA) will not be completed before your Board considers this rule. According to the report, the HIA will evaluate potential health impacts, health disparities among communities, and potential uses of any revenue generated by this proposed regulation. This is all valuable information to have before the Board makes a decision on the Cap and Trade regulation. Waiting to examine community health status, air pollution exposures, and vulnerable populations as part of the public decision-making process on the use of revenues generated by the program is unacceptable and violates the mandates of AB 32. A more complete and independent analysis needs to be done on how the Cap and Trade program will impact disadvantaged and cumulatively impacted communities. We would like to see a safeguard in place to protect sensitive areas like cumulatively impacted and/or highly populated urban areas and Class I Air Sheds (including National Parks). It is also important to have protections in place so that emitters in these areas cannot increase pollution by purchasing offsets. (CVAQC, FRESNOMINISTRY)

> **Response:** The commenters were concerned that the HIA would not be finalized before the cap-and-trade regulation was adopted, and emphasized the importance of evaluating the effects of the regulation in impacted and vulnerable populations, particularly the use of auction revenue.
>
> Both the California Department of Public Health (CDPH)'s *Health Impact Assessment of a Cap-and-Trade Framework* (HIA) and ARBs *Co-Pollutant Emission Assessment* (Emissions Assessment) were finalized prior to the Board's initial consideration of the cap-and-trade regulation. In fact, Michael Lipsett, M.D., Chief of the Environmental Health Investigations Branch at CDPH, presented a summary of the HIA findings to Board members at the December 16, 2010, Board hearing. Both the HIA and the Emissions Assessment considered the impacts of a cap-and-trade program on cumulatively impacted communities.
>
> CDPH's HIA discussed the potential impact of a cap-and-trade program on health inequities. However, as the HIA states "there is a limited ability to predict these local impacts because of scarce local level data and an inadequate ability to accurately predict or model local impacts related to cap-and-trade." Nevertheless, the document evaluates health disparities in three areas—Wilmington, Richmond, and the San Joaquin Valley. The HIA found that a cap-and-trade program with offsets would have more health benefits than a

program without offsets, specifically with regard to economic health determinants. The HIA also included recommendations on how to use the auction revenue.

Although we anticipate that co-pollutant emissions would decrease as a result of the implementation of the cap-and-trade regulation, ARB is committed to monitoring the regulation's implementation to identify and address any situations where the program has caused an increase in criteria air pollutants or toxic emissions. To assist staff in its assessment, we developed an Adaptive Management Plan that was posted for public review on October 10, 2011, and considered and approved by the Board at its October 20, 2011, public hearing. The Board's approval of the Adaptive Management Plan is reflected in Attachment C of Board Resolution 11-32.

Adaptive management is a process of information gathering, review and analysis, and response that promotes flexible agency decision-making. It is particularly appropriate where complex systems are involved, where the effects of an agency's decisions and actions play out over an extended period of time, and where the agency must meet multiple objectives—as in the case of the cap-and-trade regulation, which was adopted by the Board at its October 20, 2011, public hearing.

The adaptive management approach will allow us to collect and review applicable data sources (e.g., the MRR data, market tracking system, economic data, emission inventory, air monitoring data, and energy efficiency and co-benefits audits) and develop the appropriate tools to determine if there are impacts due to compliance with the cap-and-trade regulation as information becomes available. We will work with other State agencies and local air districts during this process. If it is determined that an adverse impact has been identified as result of the regulation, ARB will conduct a public process and report to the Board on appropriate responses.

F-4. (multiple comments)
Comment: The Cap and Trade regulation can cause Co-Pollutant hotspots, especially due to foregoing reductions of more toxic emitters for more benign ones. If a facility located in an overburdened community "buys" carbon from other facilities so that it can increase its GHG emissions, it is also increasing its emissions of toxic compounds. In addition, by mixing many different sources together into one big Cap and Trade program, the differences in co-pollutants emitted by different facilities and equipment is lost, and left unaddressed. Consequently an oil refinery CO_2 source that happens to have high benzene or high mercury, or high PM2.5 co-pollutants emissions, is treated the same as a food industry source CO_2 that burns natural gas, but has low co-pollutant emissions.

The proposed regulation does nothing to avoid hotspots or co-pollutant emissions. Yet AB 32 requires that, "*Prior to the inclusion of any market-based compliance mechanism in the regulations . . . the state board shall . . . (1) Consider the potential for direct, indirect, and cumulative emission impacts from these mechanisms, including localized impacts in communities that are already adversely impacted by air pollution; (2) Design any market-based compliance mechanism to prevent any increase in the emissions of toxic air contaminants or criteria air pollutants."*

This failure must be corrected. In fact, ARB failed to take the first step necessary to do the analysis to determine cumulative impacts. (CBE1)

Comment: AB 32 specifically requires that ARB "ensure that activities undertaken to comply with the regulations do not disproportionately impact low-income communities." The regulations may not "interfere with efforts to achieve and maintain federal and state ambient air quality standards to reduce toxic air contaminants," must minimize leakage, "consider overall societal benefits, including reductions in other air pollutants, diversification of energy sources, and other benefits to the economy, the environment and public health", and "consider the significance of the contribution of each source or category of sources to statewide emissions of greenhouse gases." But if ARB adopts a cap and trade program, AB 32 additionally requires ARB to affirmatively "design" the program "to prevent any increase in emissions of toxic air contaminants or criteria pollutants," consider direct, indirect and cumulative emission impacts from the program, and direct private and public funds to disadvantaged communities. The proposed regulation overwhelmingly ignores these requirements, and ARB's failure to analyze reasonable alternatives makes adoption of the draft regulations even more irrational.

The cap and trade regulation as currently proposed allows significant flexibility and benefits to polluters, but it impermissibly creates environmental justice problems. For example, because the regulation allows off-site reductions, we lose the potential for localized benefits and ARB creates a hard-to-track system that defeats the purpose of public vigilance and accountability. In highly impacted communities, there should be restrictions to trading to ensure meeting the requirements to not exacerbate hot spots of pollutions. If trading is restricted to within these communities, reducing local emissions of criteria and air toxics will benefit the health of these same communities that are already overburdened by pollution. Furthermore, including direct emission reduction measures will ensure real, placed-based reductions, reduce cumulative impacts, and ensure meeting the maximum feasible reductions requirement of AB 32. (CBE1)

Comment: The regulation fails to meet AB 32 criteria for market-based compliance mechanisms. The Legislature included specific protections for communities already burdened by air pollution, sought to prevent an increase in toxic exposure, and wanted to maximize benefits for California. Accordingly, the Legislature commanded the Board, before adopting a market-based compliance mechanism, to (1) consider the potential for direct, indirect and cumulative emission impacts from these mechanisms, including localized impacts in communities that are already adversely affected by air pollution;

(2) design any market-based compliance mechanism to prevent any increase in the emissions of toxic air contaminants or criteria air pollutants; and (3) maximize additional environmental and economic benefits for California, as appropriate. The proposed cap and trade regulation violates the Legislature's unambiguous commands, threatens communities with more air pollution, and fails to seize the opportunity to benefit California both economically and environmentally. The Board, if it adopts this free market hypothesis, will forgo the opportunity to generate well-paying green jobs and stimulate a California-based clean energy economy. Pollution trading creates environmentally unjust outcomes and does not work to reduce greenhouse gas emissions.

The regulation does not prevent localized or disproportionate impacts.
Because the cap and trade program offers emitters flexibility in how they reduce greenhouse gases to comply with the program, there is a substantial risk of undesirable side effects. ARB cannot anticipate where emissions reductions will occur. Because ARB cannot predict where emissions reductions and criteria pollutant co-benefits will occur, the regulation is not designed to prevent localized impacts. Nothing in the regulation actually prohibits an increase in criteria or toxic emissions. Emitters could choose to adopt a measure that reduces GHGs but increases air pollution. Reliance on other, unspecified air pollution regulations to prevent increases in co-pollutants is inappropriate and speculative. AB 32 requires the Board to "design any market-based compliance mechanism to prevent any increase in the emissions of toxic air contaminants or criteria air pollutants."

ARB admits that this threat is real. The staff report analysis states "the regulation affords entities flexibility to choose the most cost-effective strategies to reduce emissions, so the potential for some compliance actions to result in increased co-pollutant emissions at some facilities cannot be entirely discounted." ARB will only monitor the situation and take steps as necessary to address increases in criteria pollutants and toxics as they occur. The report goes on to state that pre-existing mechanisms would address the increases, such as stationary source controls, permitting programs, and air monitoring for ozone, PM2.5, and toxics. The report evidences that the cap and trade regulation is not a program designed to prevent increases—it is a program that freely acknowledges that increases are a real possibility but expects other regulations to deal with, and clean-up, cap and trade's mess. Not only does this violate the Legislature's clear command, but it is an unrealistic expectation. Many of the regulations and programs cap and trade relies on to deal with the increased pollutants are not currently meeting their attainment deadlines or were designed to reduce a specific amount of pollution that was calculated without the increased emissions from this program. The Board cannot expect these regulations to deal with the increased emissions from cap and trade. AB 32 does not allow the Board to adopt a market-based mechanism that may increase pollutants, and then provides no solution. (CRPE1)

Comment: The Staff Report analyzes potential co-pollutant increases under the cap-and-trade program in relation to the significant decreases in co-pollutants that existing regulations are expected to achieve by 2020. The state's initiatives to decrease co-pollutants are laudable. And the staff's implicit point is well-taken: if those decreases are realized, there is less of a need to use AB 32 to indirectly accomplish co-pollutant reductions. Nonetheless, AB 32 states that the state's GHG policies should be designed to complement its efforts to attain air quality standards. The cap-and-trade program, as currently designed, does not take that step.

These comments do not dispute that changes in co-pollutant levels as a consequence of GHG trading reflect the relative stringency of associated co-pollutant regulation. If a GHG trade leads to increases in co-pollutants, it is because the co-pollutant regulatory program did not prevent those increases. CARB may resist the effort to impose co-pollutant goals on its GHG regulatory program. But, as noted above, AB 32 explicitly links GHG and co-pollutant emissions by specifying that the flexibility of a market-based GHG program not lead to increases in associated co-pollutants, even if those increases would be permissible under existing co-pollutant regulations.

The Staff Report argues that existing programs are already doing enough to address pollution in California, and that trading restrictions on stationary sources would add only a marginal benefit. Ultimately, whether CARB thinks it is necessary or not, AB 32 states that California should use its GHG policies, including its market mechanisms, to further co-pollutant reduction goals. (USFLAW)

Comment: The Staff Report argues that existing air pollution regulations would keep any co-pollutant increases to a minimum. This is not the place to pick apart California's air pollution regulations, but it is not clear that they would fully address an impacted community's concerns. For example, even if NSR were triggered and the facility had to purchase criteria pollutant offsets to compensate for the increase in criteria pollutants, it is not clear that the emission reduction credits would come from the same location as the increases, potentially leading to a net increase in impacted communities notwithstanding the offset requirement. Moreover, offset requirements apply only to criteria pollutants, not air toxics. While California's "Hot Spots" program provides more attention to local emissions than occurs in most states, it does not directly prevent increases. (USFLAW)

Comment: The Staff Report suggests that co-pollutant increases are extremely unlikely to occur because the burden of New Source Review requirements and the cost of GHG allowances themselves will discourage increased emissions. At the same time, however, the Staff Report acknowledges that the state's refineries are likely to continue to supply areas outside California even if demand for fossil fuels in California drops. The Staff Report also acknowledges that new biorefineries and biomass facilities could be incentivized by AB 32 implementation measures. Thus, emissions increases are a real possibility. (USFLAW)

Comment: The California legislature expressed its concern about the distributional implications of a cap-and-trade program by explicitly stating that market mechanisms must, to the extent feasible, be designed "to prevent any increase in the emissions of toxic air contaminants or criteria air pollutants." Based on the language in the Staff Report, the staff appear to construe the language "prevent any increase" too narrowly. The staff appear to be interpreting this language to mean that the cap-and-trade program itself must not "cause" increases in co-pollutant emissions, stating that "not all emissions increases at facilities covered by the cap-and-trade program will result from the program itself. Staff believes that only in very limited circumstances would a localized emissions increase be the actual result of the incentives created by the cap-and-trade program." Under this approach, the Staff Report acknowledges that the cap-and-trade program could, in some instances, create incentives that could result in co-pollutant increases. For example, if a utility relies upon several different generation facilities, the price signal generated by the cap-and-trade program could induce the utility to increase production at more energy efficient facilities. Co-pollutant emissions could therefore increase at the more efficient facilities. Incentivizing more efficient energy generation is, of course, a positive development. Nonetheless, AB 32 requires CARB to take the co-pollutant consequences into account.

The language states that the agency is required to "prevent" increases in co-pollutant emissions, without limiting that obligation to increases caused by the cap-and-trade program itself. As the Staff Report acknowledges, facilities could choose to increase emissions in order to increase production or expand into a new type of production. New facilities could also be built. To the extent a cap-and-trade program allows facilities to increase emissions by buying GHG allowances, the GHG control program would not constrain co-pollutant increases and could be inconsistent with AB 32's requirements. (USFLAW)

Comment: AB 32 requires that ARB ensure that the regulations do not disproportionately impacted low income communities and also consider benefits to the economy, the environment, and public health. If ARB adopts the cap and trade rule, AB 32 requires ARB to design the program to prevent an increase in emissions, consider cumulative impacts, and direct public and private funds to disadvantaged communities. However, if implemented, this cap and trade rule does none of these. (CAEJA)

Comment: The regulation does not deliver emissions reductions. To meet the requirements of AB 32, this regulation must prevent any increase in the emissions of toxic air contaminants or criteria air pollutants. Cap and trade models are not successful prophylactic measures and have proven to be ineffective tools for phasing out carbon use and pollution trading is an ineffective air quality policy with the arguable exception of the Acid Trading Program. Due to over allocation of allowances, low carbon prices, fraudulent transactions and banking (which may result in short term reductions followed by a spike in emissions when banked credits are utilized), pollution trading programs do not significantly reduce air pollution. AB 32 requires ARB to "design" the cap and trade program to "prevent" any increases and to prevent localized impacts. Even if specific facilities do not increase their emissions, and continue to emit business as usual, this does not maximize co-benefits or prevent localized impacts, and as explained above, relying on other regulations to reduce emissions is inappropriate. (CRPE1)

Comment: I'm concerned that AB 32 will contain legislation that allows big polluters to continue to ruin California's air quality. Keep them responsible. One of California's major attractions is its livability. (THOMSON)

Comment: The Cap and Trade regulation can cause Co-Pollutant hotspots, especially due to foregoing reductions of more toxic emitters for more benign ones. Pollution hotspots are areas where pollution concentrates locally rather than dispersing. (Greg Karras, *Flaring hot spots: Assessment of episodic local air pollution associated with oil refinery flaring using sulfur as a tracer* CBE Report (July 2005)). Hotspots can have dire health and other quality of life consequences. For instance, modeling has shown that RECLAIM actually increased NOx concentrations in Wilmington, a low income community of color in Los Angeles, beyond what would have resulted without RECLAIM.

Hotspots are an issue in the carbon trading context because carbon dioxide is almost always released with other pollutants, or "co-pollutants. These co-pollutants can include particulate matter including heavy metals, VOCs such as benzene, sulfur compounds, and hundreds of other toxic compounds. If a facility located in an overburdened community "buys" carbon from other facilities so that it can increase its GHG emissions, it is also increasing its emissions of toxic compounds. Said another way, by taking pollution that occurs across a large area and concentrating that pollution in an environmental justice community, the toxic load in that community increases.

In addition, by mixing many different sources together into one big Cap and Trade program, the differences in co-pollutants emitted by different facilities and equipment is lost, and left unaddressed. Consequently an oil refinery CO_2 source that happens to have high benzene or high mercury, or high PM2.5 co-pollutants emissions, is treated the same as a food industry source CO_2 that burns natural gas, but has low co-pollutant emissions. This allows an oil refinery source to avoid regulation, or even expand, by buying its way out through clean-up of a facility with less toxic co-pollutants. If the oil refinery uses forest credit offsets, it definitely means that a more toxic source (an oil refinery) is offset by a less toxic source.

The proposed regulation does nothing to avoid hotspots or co-pollutant emissions. Yet AB 32 requires that,

> "Prior to the inclusion of any market-based compliance mechanism in the regulations . . . the state board shall . . . (1) Consider the potential for direct, indirect, and cumulative emission impacts from these mechanisms, including localized impacts in communities that are already adversely impacted by air pollution; (2) Design any market-based compliance mechanism to prevent any increase in the emissions of toxic air contaminants or criteria air pollutants." (CBE1)

Comment: Despite the volume and toxicity of industrial co-pollutants (especially oil industry), there are zero tons of direct controls required for this source—all are allowed to be completed through buying pollution credits from outside any particular industry, and carried out outside California or the U.S. (CBE1)

Comment: Given the acknowledged link between GHGs and co-pollutants, the state would benefit from integrating its GHG and co-pollutant reduction strategies and creating a more unified approach to regulating industrial emissions. AB 32 recognizes the connection between GHGs and co-pollutants, and instructs CARB to develop GHG reduction policies that would not only reduce GHGs, but do so in a way that "maximizes additional environmental and economic co-benefits for California, and complements the state's efforts to improve air quality." Overall, the scoping plan in general and the cap-and-trade program in particular will likely lead to improvements in air quality. That said, the cap-and-trade program does not include measures to prevent increases in co-pollutants or optimize the location of GHG and corresponding co-pollutant reductions.

The State's commitment to reduce GHGs is likely to improve co-pollutant levels and redound to the benefit of most, if not all, Californians. The state could, however, take greater initiative in fulfilling AB 32's invitation to link GHG and co-pollutant reduction benefits. (USFLAW)

Comment: I request that you very carefully consider evidence that cap and trade does not offer a solution to the air pollution problem. When the polluters are rewarded for polluting, they will not be encouraged to stop polluting. There are many people suffering physically from pollution, and these people are not the one causing it. There is a need to insert justice as a required element in the rules you make. AB 32 cannot be effective if the rules continue to permit pollution and the polluters are rewarded for it. Remember also that the entire planet needs better air. (DONOVAN)

> **Response:** The commenters claim that the cap-and-trade regulation does not fulfill the requirements outlined in AB 32; specifically the following three provisions:
>
> To the extent feasible and in furtherance of achieving the statewide greenhouse gas emissions limit, the state shall do the following:
>
> 1. Consider the potential for direct, indirect, and cumulative emission impacts from these mechanisms, including localized impacts in communities that are already adversely impacted by air pollution (Section 38570(b)(1);
>
> 2. Design any market-based compliance mechanism to prevent any increase in the emissions of toxic air contaminants or criteria air pollutants (Section 38570(b)(2);

3. Maximize additional environmental and economic benefits for California, as appropriate (Section 38570 (b)(3).

We disagree and believe that the proposed cap-and-trade regulation meets the requirements of AB 32.

Requirement 1
As noted earlier in this section, ARB evaluated the potential for localized increases in direct, indirect, and cumulative emissions in impacted communities due to a cap-and-trade program to the best of our ability during the regulatory development process. The findings of this analysis can be found in the Staff Report, in *Appendix P. Co-Pollutant Emissions Assessment*. In addition, the CDPH also investigated the potential impacts of a cap-and-trade program on health inequities, as documented in the *Health Impact Assessment of a Cap-and-Trade Framework* (HIA). We considered the results of both documents in the regulatory development process before endorsing the program.

Requirement 2
As the Emissions Assessment indicates, co-pollutant emissions in California would likely decrease as a result of a cap-and-trade program. This would mainly be attributed to an increase in efficiency and a decrease in the combustion of fossil fuels. In addition, as stated in a previous response, numerous studies have evaluated the potential for inequitable co-pollutant impacts from emissions trading programs on impacted communities and determined that either there were no impacts or that an emissions trading program could lead to co-pollutant benefits in impacted communities.

The State of California has the most stringent and successful air quality programs in the country. As described in the Emissions Assessment, our program has substantially improved the air quality in California. The cap-and-trade program will complement our existing air quality program and not impede or in any way alter existing requirements for criteria and toxic air pollutants.

Some of the commenters note specific concerns with aspects of federal, State, and district air quality regulations, and claim that they have not and would not stop air quality from worsening in their community. We acknowledge these concerns. However, the cap-and-trade regulation is not the proper venue or mechanism for addressing enforcement issues with existing regulations.

One commenter specifically states that cap-and-trade programs lead to hotspots. The commenter's evidence of this is that modeling has shown that RECLAIM increases NOx emissions in Wilmington. This is incorrect. According to the South Coast Air Quality Management District, RECLAIM has resulted in significant reductions in both NOx and SOx emissions at refineries in Wilmington. Regardless, the cap-and-trade program would overlay all source-specific rules, unlike RECLAIM, which allows facilities that participate in the trading program to opt out of certain district rules.

Although we anticipate that co-pollutant emissions would decrease as a result of the implementation of the cap-and-trade regulation, ARB is committed to monitoring the regulation's implementation to identify and address any situations where the program has caused an increase in criteria air pollutants or toxic emissions. To assist staff in its assessment, we developed an Adaptive Management Plan that was posted for public review on October 10, 2011, and considered and approved by the Board at its October 20, 2011, public hearing. The Board's approval of the Adaptive Management Plan is reflected in Attachment C of Board Resolution 11-32.

Adaptive management is a process of information gathering, review and analysis, and response that promotes flexible agency decision-making. It is particularly appropriate where complex systems are involved, where the effects of an agency's decisions and actions play out over an extended period of time, and where the agency must meet multiple objectives—as in the case of the cap-and-trade regulation, which was adopted by the Board at its October 20, 2011, public hearing.

The adaptive management approach will allow us to collect and review applicable data sources (e.g., the MRR data, market tracking system, economic data, emission inventory, air monitoring data, and energy efficiency and co-benefits audits) and develop the appropriate tools to determine if there are impacts due to compliance with the cap-and-trade regulation as information becomes available. We will work with other State agencies and local air districts during this process. If it is determined that an adverse impact has been identified as result of the regulation, ARB will conduct a public process and report to the Board on appropriate responses.

Requirement 3
The cap-and-trade program was designed to maximize a number of additional environmental and economic benefits. For example, the forest offset protocol is expected to lead to immeasurable wildlife and ecological benefits in California. The cap-and-trade program as a whole will incentivize investment in green technology.

In summary, we believe that the cap-and-trade program appropriately meets a balance for all the program objectives, including the three identified. Nevertheless, we are committed to monitoring the regulation's implementation to identify and address any situations where the program has caused an increase in criteria air pollutant or toxic emissions through a proposed adaptive management component of the cap-and-trade program.

See also response to Comment B-13.

F-5. (multiple comments)
Comment: Living in a region with high levels of air pollution due to the same stacks that are emitting GHGs, I want all of that pollution cut. It does not make sense to keep polluting or spewing out GHG emissions anywhere and especially in communities that have felt the impact of pollution for decades if not generations. Cut GHG emissions at the source for the full benefit of all Californians! (MASARENHAS)

Comment: CARB should evaluate other co-pollutants including PM2.5 and toxics which feasible direct controls would achieve. AB 32 requires addressing the co-pollutants issues, but the proposed Cap and Trade regulation and Scoping Plan do not. Large California NOx, CO, and other co-pollutant reductions can be achieved if an alternative is adopted requiring direct control measures using methods known by CARB (e.g., for boilers and heaters). These co-pollutants otherwise cause large cumulative impacts in communities of color.

Project alternatives such as requiring direct control measures would create California jobs, California health improvements, and the best model for regions outside California to replicate. They were not considered. Cost effectiveness calculation of such controls should include the benefits of reducing GHGs, reducing smog and toxics, and reducing health impacts. (CBE1)

Comment: Boiler and Heater NOx and CO Co-pollutant emissions are large and if directly controlled would yield large local health benefits. AB 32 requires ARB to design the program to prevent any increase in emissions of toxic air contaminants or criteria pollutants. It also requires it to consider the overall societal benefits of reducing other air pollutants and benefits to the environment and public health. Yet the draft regulation demonstrates that reductions could have been achieved to substantially reduce co-pollutant emissions but was rejected. If these controls were implemented locally instead of traded, they would not only result in the CO_2 emissions reductions identified by CARB, but would also result in very substantial co-pollutant reductions. CARB should have considered such an alternative project to address co-pollutant impacts. (CBE1)

Comment: Pollution trading often does not result in emissions reductions because of increased difficulty monitoring and enforcing emission reductions. Instead of relying on trading, ARB should focus on direct emission reductions, “a greenhouse gas emission reduction action made by a greenhouse gas emission source at that source.” By requiring emissions reductions at the source, ARB will provide certainty that emissions reductions will occur and can determine where the reductions will occur. Thus, ensuring that environmental justice communities will get an equitable share of the co-benefits of reducing greenhouse gas emissions. In addition, direct emission reduction measures can provide targeted co-benefits and ensure an appropriate level of GHG and co-pollutant reductions. (CRPE1)

Comment: Refining areas are in need of direct, local pollution controls, not the potential for further concentration and expansions that the Cap and Trade proposal makes likely, through allowing refineries to buy their way out of local pollution control. (CBE1)

Response: Several of the commenters suggested that ARB should directly regulate greenhouse gas emissions from stationary sources instead of pursuing a cap-and-trade program.

The cap-and-trade program creates a limit on the emissions from sources responsible for 85 percent of California's GHG emissions, establishes the price signal needed to drive long-term investment in cleaner fuels and more efficient use of energy, and affords covered entities flexibility to seek out and implement the lowest-cost options to reduce emissions. The cap-and-trade program is designed to work in concert with other measures, such as standards for cleaner vehicles, low-carbon fuels, renewable electricity, and energy efficiency. The program will also complement and support California's existing efforts to reduce criteria and toxic air pollutants.

When developing the Scoping Plan in 2008, and in the Staff Report for the cap-and-trade regulation, we evaluated the air quality impacts of a direct regulatory approach compared to a cap-and-trade program.

A cap-and-trade program has the distinct advantage of imposing an enforceable cap on emissions—making it the most likely method to successfully meet the AB 32 goal of capping emissions at 1990 levels by 2020. As described on pg. IV-3 of the Staff Report, direct regulations for emission sources do not provide the same assurance of reductions as those offered by a cap-and-trade program.

Emissions reductions from command-and-control regulations are estimates based on assumptions about the specific regulation, and they typically result from reducing the emissions intensity of the regulated activity. These assumptions may include forecasts of technology development and penetration estimates. Although these estimates would be based on the best data available, actual results may be different because regulations may fail to achieve expected reductions, or programs may not be funded at adequate levels or may be less effective than projected. In addition, increases in the regulated activity (e.g., an increase in throughput) could mean that the regulation has the effect of reducing emissions intensity but the absolute level of emissions could actually increase over time. A cap-and-trade program, on the other hand, would establish the maximum level of total GHG emissions allowed to be emitted collectively by all covered sources. Because the cap-and-trade program sets a cap on the GHG emissions from the majority of California's GHG emissions, it helps ensure that the State will meet the AB 32 statewide emissions limit.

Source-specific regulations are also unlikely to be as cost-effective at reducing GHG emissions as the proposed cap-and-trade program. The cap-and-trade program is designed to allow broad flexibility for the covered entities to find the most cost-effective GHG emissions reductions by reducing their GHG emissions, buying allowances from an entity that does not need them for compliance, or purchasing offset credits. With source-specific regulations, entities have limited flexibility and must comply with the regulation, no matter what it costs. Even though each source-specific regulation must undergo cost-effectiveness analyses, it may not necessarily be the most cost-effective for the industry and economy as a whole because cost-effective reductions are not necessarily evenly distributed through all industrial sectors.

In addition to lacking emissions-reductions certainty, and having the potential to be less cost-effective at reducing emissions, industry-wide command-and-control regulations would be time consuming to develop and challenging to draft and implement. To develop these regulations, ARB would need to identify and target specific processes and equipment and formulate regulations for each. Due to the diverse nature of many industrial processes and a lack of data, it is not practical for ARB to craft and implement such regulations at this time. However, ARB will use information collected through the mandatory reporting regulation, the cap-and-trade regulation, the industrial efficiency audit, and other sources to evaluate how facilities are complying with the cap-and-trade regulation, and to evaluate additional opportunities for cost-effective emission reductions at large stationary sources subject to the program.

F-6. (multiple comments)
Comment: We have concerns about the approach CARB staff used to conduct the emissions assessment. We believe the approach should ensure we are analyzing the specific impacts (both emissions and corresponding health impacts) of the cap and trade regulation exclusively, utilizing a smaller/neighborhood-level analysis to assess localized impacts, and including an analysis of the impacts from the use of offsets. In addition, we urge CARB to commit to specific benchmarked ongoing monitoring. (CCA1)

Comment: AB 32 directs CARB to develop policies that “complement the state’s efforts to improve air quality.” It is not enough to prevent co-pollutant increases. Ideally, the cap-and-trade program should help achieve air quality standards by targeting GHG, and associated co-pollutant, reductions in the state’s most polluted areas. Not surprisingly, CARB’s Co-Pollutant Emissions Assessment reveals that greater co-pollutant reductions benefits would be achieved if all facilities had to reduce their proportionate share than will be achieved by letting facilities trade GHG allowances in ways that could maintain or increase emissions. For example, in the Wilmington case study, if facilities reduced their GHG emissions by their proportionate share rather than increasing emissions, co-pollutant reductions would be enhanced by 2 percent for NOx, 3 percent for PM2.5, and 1 percent for ROG. While the percentage difference in emissions reductions is small, the data indicates that the cap-and-trade program has not been designed to enhance the achievement of air quality objectives.

In addition, the emissions assessment does not evaluate what could have been achieved if the program were designed to require or incentivize greater GHG reductions in the state's most polluted areas. The first scenario in all of the report's case studies assumes that all facilities in the state reduce by the same amount. The report does not analyze the co-pollutant consequences of achieving greater-than-average GHG reductions in the state's most polluted areas. (USFLAW)

Comment: The case studies in the emissions assessment do include emissions increase scenarios, evaluating both the possibility that facilities would increase GHG emissions by 4 percent and the possibility of a new source in each study area. The Staff Report reveals that these GHG emissions increases would lead to small increases in co-pollutants relative to the baseline scenario. For example, in the Wilmington case study, if GHG emissions increased by 4 percent, then, in comparison with the baseline scenario resulting from current criteria pollutant controls, there would be 1 percent less NOx reduction, 2 percent less PM2.5 reduction, and 1 percent less ROG reduction. Achieving less reduction is tantamount to increasing emissions relative to the baseline; co-pollutant emissions would be higher than they would have been had the facilities reduced instead of increasing GHG emissions. Moreover, it is possible that major facility expansions could lead to increases above 4 percent and that more than one new facility could choose to locate in certain areas, possibilities not considered by the assessment. (USFLAW)

Comment: The co-pollutant emissions assessment conducted has many limitations and does not include major source categories coming into the program in 2015. Historical data and similar previous hypothetical analyses have consistently shown that such model-based predictions (such as the 1990's SIPs which expected attainment of ozone standard by 2010) have often proved to be wrong.

According to the Scoping Plan, 169 MMT of CO_2E reduction per year is associated with a co-benefit of reducing $PM_{2.5}$ by 15 tons/day. Applying the same ratio in a cumulative context, the proposed amount of offsets equates to losing the co-benefit of reducing $PM_{2.5}$ by 2.3 tons/day—this could translate to about 100-120 deaths. The emission reduction programs funded by the CBF will reduce this burden significantly and maximize the co-benefits as required by AB 32. (CCA2)

Comment: ARB conducted a "Co-Pollutant Emissions Assessment" in four areas of the state and concludes that the cap-and-trade regulation is expected to have a beneficial effect on emissions. This conclusion is arguably justifiable because of the approach taken to compare the emission changes in the context of background levels and the size of the area considered for evaluation. We believe that the assessment should have included evaluation scenarios of emission impact changes expected in the vicinity of emission sources (for example, at the fence line and 0.5 mile radius) as opposed to comparing it to the total emissions from all sources in a large area. The historical data and previous assessments have consistently shown that predictions from similar macro scale modeling based on emission inventories have often proved to be misleading and have very limited accuracy in their predicting value. In almost all of the previous regulatory development processes, the tonnage reduction or potential increase of emissions was estimated for that particular (specific) regulation and was estimated along with associated health benefits. Staff argues that due to lack of information on the concentration, location, duration of air pollutant exposures, unique surrogate for the large industrial sources and data to conduct air quality modeling prevented them to conduct a health assessment. However, with similar limitations many previous regulations and reports (goods movement, diesel emission reduction plan) including the Scoping Plan have estimates of health benefits. Furthermore, by incorporating other existing regulations into the assessment, CARB is not providing the focused evaluation of the cap-and-trade program we anticipate is envisioned in AB 32. The assessment also neglects to consider the cumulative impact of offsets proposed in the cap-and-trade program. The total offsets limit proposed is about 232 MMT CO_2E or an average of 26 MMT per year (lower in early years and higher in later years). According to the Scoping Plan, 169 MMT of CO_2E reductions per year is associated with a co-benefit of reducing PM2.5 by 15 tons/day. Applying the same ratio in a cumulative context, the proposed amount of offsets equates to losing the co-benefit of reducing PM 2.5 by 2.3 tons per day. This could be translating to about 100-120 deaths annually. The above scenario is neither acknowledged in the proposed regulation nor has any real and viable solution to initiate or augment co-pollutant emission reduction efforts recommended in the proposal. (CCA1)

Comment: Framework for the Co-Pollutant Emissions Scenarios is flawed. CARB did not properly assess the co-pollutant risk. Co-Pollutant Emissions Assessment is limiting in that it only identifies four “impacted communities” for the purposes of demonstrating the hypothetical bounding exercise and has a problematic boundaries for the communities. ARB should reduce the scale of this assessment to magnify the local communities that are experiencing high exposures to pollution. It is unclear why CARB chose to exclude the West Oakland community and the Port of Oakland and yet, include predominately white, upper class and upper middle class cities such as Piedmont, Orinda and Regional Parks areas in East Contra Costa County. If the intent was to give a regional assessment, CARB should have included the East Bay communities where local PM 2.5 daily concentrations are exceeding federal standards. Low-income communities of color such as in East Oakland are overburdened by exposure to fine particulates and other pollutants and are vulnerable to cumulative impacts. (CBE1)

Comment: ARB includes three scenarios for Community Case Studies (Appendix P-50). We find Scenario 1—where all covered facilities reduce within the community and use offsets within the community—highly unlikely in the regulation’s proposed form in Richmond and Wilmington, due to expected trends in increasing refinery capacities and the unlimited geographic boundaries of the offset program. There are no requirements or incentives to do this; in fact the whole regulation is stated to be designed for trading across state and international lines. However, this scenario could be more likely if the regulation is amended to geographically restrict trading and offsets. Scenario 2—where all covered facilities increase their emissions—seems very likely, especially for sources like refineries, which are attempting to expand and will have to purchase offsets or additional allowances. Scenario 3—where a new combined heat and power unit at an existing refinery is built in the community—there is a major deficiency in the analysis because it does not account for the possibility that refineries will utilize this increased efficiency in one area of the refinery to allow increased capacity to refine heavier, dirtier crude, resulting in a net increased emissions and exacerbating localized impacts. For example, CARB and the Air Quality Management Districts are well aware that this is the standard approach used in air permitting, and routinely carried out during expansions. Furthermore, due to the flexibility of the proposed regulation, we find the equally apportioned 4 percent greenhouse gas reduction at every cap-and-trade industrial and electricity generation facility in the community region extremely unrealistic. (CBE1)

> **Response:** The commenters suggested that the Co-Pollutant Emissions Assessment should have evaluated additional scenarios, the scenarios selected are unrealistic, and ARB should have analyzed the change in co-pollutant emissions in the State's most polluted areas.
>
> We evaluated the potential for localized increases in co-pollutant emissions in impacted communities due to a cap-and-trade program to the best of our ability, given resources and data availability (see the response earlier in the section for details). Due to the variety of compliance options available, it was not feasible to analyze the impacts of every potential hypothetical change in greenhouse gas emissions in every community. Instead, we selected scenarios to bound the potential range of co-pollutant emission changes that could occur in a community. We then analyzed the change in co-pollutant emissions in four communities that are adversely impacted by air pollution—Wilmington, Oildale/Bakersfield, Richmond, and Apple Valley/Oro Grande—which have a significant concentration of industrial sources. As stated below, these four communities were selected using a variety of methods and through consultation with the Environmental Justice Advisory Committee (EJAC).
>
> A few of the commenters estimated the quantity of premature deaths that are not avoided by including offsets in the cap-and-trade program using estimates from the Scoping Plan. It is not appropriate to apply the ratio used in the Scoping Plan to the co-pollutant emissions that would be reduced under a cap-and-trade program to estimate the impacts. Instead please refer to the Co-Pollutant Emissions Assessment in the Staff Report.
>
> The methodology used in the Scoping Plan report for estimating premature deaths associated with particulate matter less than 2.5 microns in diameter (PM2.5) is outdated. We routinely prepare cost-benefit analyses as part of promulgation of regulations designed to reduce air pollution. These cost-benefit analyses include estimates of the health benefits, and the dollar value associated with a proposed regulation. We quantify some of the health impacts associated with exposure to current and future levels of ambient particulate matter. The methodology used in these analyses is periodically updated as new scientific literature is published.

In 2010, we updated the methodology for estimating premature mortality related to long-term exposure to PM2.5 in response to a new review of the National Ambient Air Quality Standards for Particulate Matter by the U.S. Environmental Protection Agency (U.S. EPA). That review included the most recent peer-reviewed scientific literature on the health effects of PM2.5, and one of its findings is that there is a causal relationship between PM2.5 exposure and premature death. We adopted the U.S. EPA's PM2.5 risk assessment methodology because it represents the most scientifically defensible basis for making estimates of the health benefits of PM2.5 regulations.

In addition, the HIA found that a cap-and-trade program with offsets would have more health benefits than a program without offsets, specifically with regard to economic health determinants. As previously indicted, staff anticipate that co-pollutant emissions would decrease as a result of the implementation of the cap-and-trade regulation. However, ARB is committed to monitoring the regulation's implementation to identify and address any situations where the program has caused an increase in criteria air pollutants or toxic emissions. To assist staff in its assessment, we developed an Adaptive Management Plan that was posted for public review on October 10, 2011, and considered and approved by the Board at its October 20, 2011, public hearing. The Board's approval of the Adaptive Management Plan is reflected in Attachment C of Board Resolution 11-32.

Adaptive management is a process of information gathering, review and analysis, and response that promotes flexible agency decision-making. It is particularly appropriate where complex systems are involved, where the effects of an agency's decisions and actions play out over an extended period of time, and where the agency must meet multiple objectives—as in the case of the cap-and-trade regulation, which was adopted by the Board at its October 20, 2011, public hearing.

The adaptive management approach will allow us to collect and review applicable data sources (e.g., the MRR data, market tracking system, economic data, emission inventory, air monitoring data, and energy efficiency and co-benefits audits) and develop the appropriate tools to determine if there are impacts due to compliance with the cap-and-trade regulation as information becomes available. We will work with other State agencies and local air districts during this process. If it is determined that an adverse impact has been identified as result of the regulation, ARB will conduct a public process and report to the Board on appropriate responses.

Adaptive management is consistent with ARB's long-standing approach to program implementation which incorporates ongoing evaluation of how programs and regulations are implemented on the ground, regular updates to the Board, and adjustments to program implementation and regulatory requirements, as necessary.

F-7. (multiple comments)
Comment: All of California will benefit from the improved health and lower pollution levels that will result from CARB's implementation of California's landmark legislation. We believe these policies can improve our energy security, create new business opportunities and more jobs, and provide incentives for innovation. (UCS3)

Comment: CIPL joins with other public health and environmental justice organizations in supporting the public health assessments of the cap and trade scenarios by the Department of Public Health and the Air Resources Board. (CIPAL)

Comment: Catholic Charities supports the efforts by the ARB and the Department of Public Health to conduct public health assessments. (CATHCHAR1)

Response: Thank you for the comments. We appreciate the support.

F-8. (multiple comments)
Comment: In order to make sure that public health at the community level is safeguarded, ARB should require an ongoing review and update of the co-pollutant emissions assessment included in the Initial Statement of Reasons, and should continue to work with the Department of Public Health in ongoing review and evaluation of the impacts of the Cap-and-Trade program. (SIERRACLUBCA4)

Comment: We urge CARB to require an ongoing review and update of the Co-Pollutant Emissions Assessment (Assessment) included in the Initial Statement of Reasons once the Cap and Trade Program is enacted. As mentioned earlier, we believe the community emissions assessment is important to the regulatory development and review process. We appreciate that multiple cap and trade scenarios that were analyzed for Wilmington, Oildale/Bakersfield, Richmond, and Apple Valley/Oro Grande including several different compliance choices by facilities (facility upgrades to reduce emissions, the purchase of allowances or reliance on offset purchases). This analysis provides a helpful step forward in understanding the range of potential communitywide air quality and emission impacts based on assumptions of future facility actions. As your analysis notes, however, it is difficult to know what facility-specific changes will actually occur under cap and trade and how this will impact emissions. Therefore, as the program is implemented, it is important to specifically require an ongoing, updated assessment of emissions in order to get a clearer picture of how the cap and trade program is actually impacting pollution emissions in communities and to capture any localized impacts not included in the initial analysis. While the Assessment indicates that staff will evaluate how the facilities are complying with the regulation at least once every compliance period, we believe more specific direction is needed in the regulation. (KUSTIN02, KUSTIN11, KUSTIN12)

Comment: The proposed regulation states that CARB will monitor the co-pollutant consequences of the trading program and take further action as appropriate. Such monitoring will provide an important opportunity to assess the program. However, the report indicates that such an assessment will occur only once a compliance period—once every three years. That appears to be too infrequent to properly monitor the program's co-pollutant consequences. (USFLAW)

Comment: As AB 32 and the Cap and Trade program go forward, we request that ARB conduct ongoing reviews and updates of the co-pollutant emissions assessment. We hope the Department of Public Health and ARB will continue working with each other to conduct broader assessments of the impacts to public health. (CATHCHAR1, CIPAL)

Comment: We wanted to reinforce the importance of ongoing assessment of emission impacts and health surveillance in local communities. And we want to work with you to get this built into the periodic review discussed in the periodic regulation review that's discussed in the 15-day changes in Attachment B. (ALA)

Comment: We urge CARB to continue to work with the Department of Public Health (DPH) in ongoing review and evaluation of public health aspects of the Cap and Trade program. Similar to the emissions assessment, we believe CARB should continue to work with DPH to conduct broader assessments of public health impacts as the program is implemented. (KUSTIN11, KUSTIN12)

> **Response:** Although we anticipate that co-pollutant emissions would decrease as a result of the implementation of the cap-and-trade regulation, ARB is committed to monitoring the regulation's implementation to identify and address any situations where the program has caused an increase in criteria air pollutants or toxic emissions. To assist staff in its assessment, we developed an Adaptive Management Plan that was posted for public review on October 10, 2011, and considered and approved by the Board at its October 20, 2011, public hearing. The Board's approval of the Adaptive Management Plan is reflected in Attachment C of Board Resolution 11-32.
>
> Adaptive management is a process of information gathering, review and analysis, and response that promotes flexible agency decision-making. It is particularly appropriate where complex systems are involved, where the effects of an agency's decisions and actions play out over an extended period of time, and where the agency must meet multiple objectives—as in the case of the cap-and-trade regulation, which was adopted by the Board at its October 20, 2011, public hearing.
>
> The adaptive management approach will allow us to collect and review applicable data sources (i.e., the MRR data, market tracking system, economic data, emission inventory, air monitoring data, and energy efficiency and co-benefits audits) and develop the appropriate tools to determine if there are impacts due to compliance with the cap-and-trade regulation as information

becomes available. We will work with other State agencies and local air districts during this process. If it is determined that an adverse impact has been identified as result of the regulation, ARB will conduct a public process and report to the Board on appropriate responses. We will report to the Board at least annually on the implementation of the Adaptive Management Plan.

Adaptive management is consistent with ARB's long-standing approach to program implementation which incorporates ongoing evaluation of how programs and regulations are implemented on the ground, regular updates to the Board, and adjustments to program implementation and regulatory requirements, as necessary.

F-9. Comment: The cap and trade program should have a more direct linkage between specific industrial and utility sector allowance allocations to specific actions that benefit historically disadvantaged communities and low-income ratepayers. Concurrently, CARB should err on the side of under allocation when doling emissions allowances to major sources in disadvantaged and historically impacted communities. (EDF1)

Response: Utilities must use the value of their allowances on behalf of rate-payers. Our intent is to provide free allowances solely to transition to a program that relies on auction and prevents leakage. As stated in Board Resolution 10-42, the Board agreed with the recommendations of the Economic and Allocation Advisory Committee, including financing economic opportunities and environmental improvements in disadvantaged communities. We are currently developing recommendations on the use of auction proceeds and will examine potential applications in disadvantaged communities.

G. DEFINITIONS

This section includes specific comments and associated responses about definitions, and primarily concerns section 95802 of the regulation.

G-1. (multiple comments)
Comment: The first deliverer of electricity is currently defined either as the "owner or operator" of an electricity generating facility in California or an electricity importer. Because the point of regulation for the electricity sector is the first deliverer, it is critical that the definition be certain and unambiguous. In the majority of cases, the operator is also the owner, but there are cases where the owner may include multiple parties and the operator may be one of those owners acting on behalf of all the owners. LADWP recommends that this be corrected for consistency with subarticle 3, section 95811, such that for an in-state electricity generating facility only the operator is the first deliverer, and not the owner of the facility. (LADWP1)

Comment: The definition of “First deliverer of electricity” should be clarified. “First deliverer of electricity” is defined in section 95802(a)(71) (p. A-17) as “either the owner or operator of an electricity generating facility in California or an electricity importer.” However, in section 95811(b)(1) (p. A-40), the operator, not the owner or operator, of an electricity generating facility in California is specified as being the covered entity for electricity generating facilities. The definition of “first deliverer of electricity” in section 95802(a)(71) implies that there is a choice about whether the owner or the operator of a facility will be the covered entity for an electricity generating facility, but allowing a choice may cause problems, given that the operator, not the owner, is required to report under the revised MRR, given that the owner and the operator of a facility are different entities in many cases, and given that many generating facilities are jointly owned. ISOR for the revised MRR notes (p. 135) the importance of avoiding ambiguity as to the entity with reporting obligations. It is even more important to avoid ambiguity as to the entity with cap and trade compliance obligations. The simplest approach would be to follow section 95811(b)(1) and revise section 95802(a)(71) to refer to the operator only rather than to “either the owner or operator” of an electricity generating facility. (SCPPA1)

> **Response:** We agree and modified the definition of "First Deliverer of Electricity" to only include the operator of the facility and not the owner.

G-2. Comment: The definition of greenhouse gases within Section 95802 does not include fluorinated compounds listed within 40 CFR Part 82, subpart A. This definition is inconsistent with the compounds listed within the ODS protocol in this regulation; all of which are listed within 40 CFR Part 82, subpart A. (CAPCOA1, CAPCOA2)

> **Response:** The definition of “Greenhouse Gas” was modified to make it consistent with terminology in AB 32, and includes only the six greenhouse gases listed therein. Nothing in AB 32 limits ARB from identifying additional GHGs that may be included in Compliance Offset Protocols. The ODS protocol

compounds are defined in the ODS protocol which is incorporated by reference into the regulation.

G-3. Comment: The reference to "hydrocarbons" within the definition of Greenhouse Gases in section 95802(a)(84) needs to be removed. (PMTPETRO1, CCEEB1, WIRA1)

Response: We agree and modified the definition of "Greenhouse Gas" to not include hydrocarbons, consistent with terminology in AB 32.

G-4. Comment: ATA recommends a change to the definition of "Kerosene" to address a typographical error. We are fully supportive of ARB's proposal to exclude jet fuel from the definition of kerosene. To fully effectuate this, ATA recommends that the word "include" be inserted into the last sentence of the definition of "Kerosene," (section 95802(a)(104)), in order to address an apparent typographical omission. With this insertion, the sentence should read, "Kerosene does not include kerosene-type jet fuel." (ATAA)

Response: We corrected the typographical error.

G-5. Comment: Section 95985 makes extensive reference to the concept of replacing credits in the event of a reversal, but the term is not defined. "Replace" should be a defined term, perhaps defined as transferring a compliance instrument into the Retirement Account established pursuant to section 95831(3). (SHILLINGLAW1)

Response: We modified section 95985 and believe the revisions clarify what is meant by replacing an offset credit. Specifically, an entity "must replace each metric ton of CO_2e with a valid ARB offset credit or another approved compliance instrument."

G-6. Comment: "Solid waste materials" should be defined in Section 95852.2(a)(1). (LASD1)

Response: For consistency, we replaced the undefined term "solid waste materials" with the term "Municipal Solid Waste," where applicable. In addition, we modified the definition of "Municipal Solid Waste" to clarify the types of material that would fall under this category.

G-7. (multiple comments)
Comment: Section 95802(a)(207) defines "Voluntarily Associated Entity" as "any entity which does not meet the requirements of section 95811 in this article that intends to voluntarily retire compliance instruments in the cap-and-trade program," while section 95814(a)(2)(A) more broadly defines the role of a Voluntarily Associated Entity as "an entity that does not meet the requirements of sections 95811 and 95813 that intends to purchase, hold, sell, or voluntarily retire compliance instruments." NCPA recommends that these definitions be reconciled so that they are consistent. (NCPA1)

Comment: The definition of voluntarily associated entity needs to be corrected. CERP strongly supports ARB's creation of an open market for trading in compliance instruments. CERP believes that allowing a wide variety of entities to participate in the market will ensure a liquid market and reduce the potential for any one entity to exercise market power. However, the definition of "voluntarily associated entity" in the proposed regulations provides that such an entity must have an intent to voluntarily retire compliance instruments. This appears to be an error because other provisions make clear that a "voluntarily associated entity" can be a broker or other liquidity provider. (CERP1)

> **Response:** We agree and modified the definition for consistency.

G-8. Comment: Section 95857(c)(5) gives CARB's Executive Officer the power to identify holding accounts controlled by "affiliates" of the deficient covered entity to which the covered entity has transferred compliance instruments and prevent transfers from the holding accounts and retrieve allowances from them to address the deficient surrender by the covered entity. However, "affiliate" is not defined. (CAPCOA1, CAPCOA2)

> **Response**: We modified section 95857(c) to outline the consequences of not meeting the untimely surrender obligation. As a result, the term "Affiliate" was deleted from subsection (c)(5).

G-9. (multiple comments)
Comment: We believe the definition of what constitutes a "beneficial ownership" relationship needs to be brought into sharper focus. A Beneficial Ownership designation should be limited to a party that has an arrangement with the account owner that allows it to direct the account owners management and disposition of the allowances held beneficially for it. (MSCG2)

Comment: Section 95915(b) (p. A-102) sets out a very broad definition of "bidding association." An entity would be in a "bidding association" if the entity had "any form of agreement with another entity" or "has agreed to provide assistance to the other entity in any way" except for investment or auction advisory services. The definition of "bidding association" should be narrowed to include only agreements relating to the allowance auctions. Modify this section as follows:

> An entity has a disclosable "bidding association" with another entity if it:
> (a) Has any form of agreement with another entity <u>relating to the allowance auctions; or</u>
> (b) Is partnered with another entity for bidding purposes; <u>or</u>
> (c) Has agreed to provide assistance <u>in relation to the allowance auctions to the other entity</u> in any other way, with the exception of investment or auction advisory services ~~with the other entity~~. (SCPPA1)

G-10. Comment: The Utilities request further explanation of subsection 95915(b) as to the description of what a disclosable bidding association is. As currently written in the proposed regulation, the definition of a "bidding association" is vague and further clarification of the types of agreements and assistance being referred to is needed. For example, the ISOR (page IX-101) appears to indicate coverage only for entities that provide advisory services (presumably although not explicitly stated) related to allowance auction bids. However, subsection 95915(b)(3) refers very broadly to any "assistance." The Utilities request that subsection 95915(b) be revised to define the realm of agreements and assistance that would create "bidding associations." (MID1)

> **Response**: We agree that "Beneficial Ownership" and "Bidding Association" needed clarification. We modified the regulation by deleting section 95915, along with the term "Bidding Association." In addition, new sections 95833 (Disclosure of Direct and Indirect Corporate Associations) and 95834 (Disclosure of Beneficial Holding) were added to clarify language in the appropriate context within the regulation. New section 95833 is composed generally of modified text that originally appeared as sections 95914(a) through (d). This section additionally requires all registered entities to identify if they share specific types of relationships with other registered entities. This information is needed to monitor for suspicious activity in the market program and ensure market rules are not circumvented. New section 95833(a)(2) was modified from original text to clarify an existing requirement that an entity holding compliance instruments on behalf of another entity in a beneficial holding relationship is considered to have a direct corporate association with the other entity.
>
> New section 95834 provides detailed provisions for an existing requirement that any entity holding compliance instruments on behalf of another entity disclose the relationship to ARB. New section 95834(a)(1) defines when a beneficial holding relationship exists. It also defines an agent as an entity holding allowances owned by a second entity, which is defined as the principal. New section 95834(a)(2) creates a type of beneficial holding relationship for electric distribution utilities that may need to hold compliance instruments on behalf of entities with whom they have long-term electricity delivery contracts, which may not explicitly determine which party to the contract has the responsibility to surrender compliance instruments. Section 95834(a)(3) allows entities that have disclosed a corporate association pursuant to section 95833 to utilize the beneficial holding arrangements.

G-11. Comment: Section 95852.2(a) references emissions from sources which do not have a compliance obligation specifically excepting biogas from digesters. However the term "Biogas" is not defined. A definition should be added. Modify section 95802 as follows:

> <u>Biogas - gas from the anaerobic digestion of organic wastes.</u>

Also Section 95852(e) specifically lists emissions of Biomethane from animal and other organic waste and landfill gas and wastewater as specifically exempted from creating a compliance obligation and yet "Biomethane" is likewise not defined. A definition for "Biomethane" should be added. Modify section 95802 as follows:

> Biomethane - is biogas that has been upgraded or otherwise conditioned to meet CPUC natural gas specifications and is suitable for injection into natural gas pipeline systems operated by public and private utilities. (SEMPRA1)

> **Response**: We agree, and added definitions for biogas and biomethane to section 95802. The definition of biomethane does not reference biomass, but rather, is defined as biogas that meets pipeline-quality natural gas standards.

G-12. Comment: I understand that staff plans to add a defined term "biomethane" as "pipeline-quality biomass-derived fuel." If staff does adopt use of "organic" or "organically derived" in place of the current use of "biomass" to mean anything once living that is not now a fossil, the current use of "biomass" in the proposed regulation that is something very much broader than the meaning of the word "biomass" this definition would instead read something akin to "pipeline-quality organically derived fuel." (WEINSTEIN)

> **Response**: We agree, and added definitions for biogas and biomethane to section 95802. The definition of biomethane does not reference biomass, but rather, is defined as biogas that meets pipeline-quality natural gas standards.

G-13. Comment: The definition of electricity generating unit should be corrected. The definition of electricity generating unit listed at 95802(a)(58) incorrectly excludes some major facilities that are primarily electrical generation assets wholly owned by SMUD (and controlled to provide a critical component in SMUD's bulk transmission grid) but are also cogenerators supplying steam to nearby facilities not owned by SMUD. The definition should be changed as follows:

> (58) "Electricity generating facility" means a facility whose primary ~~sole~~ purpose is to generate electricity for the grid rather than on-site use and which includes one or more electricity generating units at the same location. ~~"Electricity generating facility" does not include a cogeneration facility or self-generation~~. (SMUD1)

> **Response:** We agree that an "electricity generating facility" should not exclude cogeneration facilities and modified the definition accordingly.

G-14. Comment: The definition of "intentional reversal" in section 95802(99) is overbroad to the extent that it attempts to penalize landowners for "negligent" loss of carbon stocks. This standard is extremely subjective and difficult to define. For instance, if a landowner maintains a highly stocked stand in order to maximize carbon and this increases fire risk which causes a reversal, is this negligence? Or if a landowner chooses not to preemptively thin a stand which is vulnerable to disease in order to maximize carbon and the entire stand is affected by disease causing a reversal, is this negligence? We recommend the definition be amended to reflect the current CAR Forest Carbon Protocol language that an intentional reversal is a result of "intentional or grossly negligent acts of the forest owner." (FCC, BLUESOURCE)

> **Response**: If a well-stocked forest that is managed in accordance with applicable forestry regulations and project objectives suffers from an unintended wildfire, this would not constitute negligence. A fire attributable to a forest owner's failure to follow laws and regulations or approved harvest and management plans would be negligence. Whether or not a reversal is intentional or not has a direct bearing on how the invalidated forest offset credit is replaced and by whom. We believe it is important to have the current language to ensure a comprehensive evaluation is allowed in determining how to replace the invalidated forest offset credit.

G-15. (multiple comments)
Comment: SCE requests clarification on the definition of a "California greenhouse gas emissions allowance" found in section 95802 of the proposed regulation. This definition states that allowances issued by CARB will be "equal to up to one metric ton of CO_2 equivalent." All allowances should be worth the same amount: exactly one metric ton of CO_2 equivalent. SCE requests that CARB confirm this interpretation, as there can be no functioning market for allowances without precise standards and measurements. (SCE1)

Comment: Section 95802(a)(27) (p. A-10) defines "California greenhouse gas emissions allowance" as "an allowance issued by ARB and equal to up to one metric ton of CO_2 equivalent." However, "allowance" is separately defined in section 95802(a)(5) (p. A-7) as a "limited tradable authorization to emit up to one metric ton of carbon dioxide equivalent." Given the definition of "allowance," the definition of "California greenhouse gas emissions allowance" should be "an allowance issued by ARB under this Article" if not eliminated altogether as redundant. Modify this section as follows:

"California greenhouse gas emissions allowance" or "CA GHG Allowance" means an allowance issued by ARB <u>under this Article</u>~~ and equal to up to one metric ton of CO2 equivalent~~. (SCPPA1)

> **Response**: The smallest accounting unit for emissions or compliance instruments is a metric ton. That is, if a covered entity was responsible for a compliance obligation that was some fraction of a ton, that entity would turn in an allowance for a whole ton. Therefore, we did not change this definition.

G-16. (multiple comments)
Comment: Recognize Carbon Capture and Storage by including its definition in section 95802. Including a definition of CCS in the rule will facilitate its further consideration during development of the implementing regulations. (APC)

Comment: Recognize Carbon Capture and Storage explicitly within the Regulation by including a definition of CCS in Section 95802. A definition of CCS within the regulation is clearly necessary so that as the cap and trade program develops, there is an accepted standard that stakeholders can reference. It also provides acknowledgement by the Board that CCS is an accepted strategy in achieving the short and long-term goals of the program. Hydrogen Energy suggests the following definition as used by the California CCS Review Panel: "Carbon capture and storage (CCS) refers to the capture, or removal, of carbon dioxide (CO_2) at large industrial sources and its subsequent compression, transport, and injection into the subsurface for long term or permanent storage." (HECA)

> **Response**: The terms "Carbon Dioxide Supplier" ("facilities…that capture the CO_2 stream in order to utilize it for geologic sequestration") and "Geologic Sequestration" included in section 95802 (definitions) acknowledge that CCS may have potential in the program.

G-17. Comment: Clarify forest owner definition with respect to conservation easement holders. The revised definition of forest owner needs to be clarified with respect to easement holders. The definition asserts that easement holders are not considered a forest owner, but proceeds to define forest owner to include entities that may hold timber rights. However, easement holders may hold timber rights as part of a conservation easement, which creates an inconsistency in the definition. Therefore, the definition does not need to include an explicit exclusion of easement holders. If there are particular sections of the Protocols that should exclude easement holders from obligations of forest owners, those sections should make this explicit. (NC1, NC2)

> **Response:** We changed the definition of "Forest Owner" to remove the exemption of conservation easement holders, and will continue to work with stakeholders to evaluate the merits of the suggested edits.

G-18. (multiple comments)
Comment: "Forest owner" should be defined to exclude the fee owner when all timber rights are held in perpetuity by another entity. If one entity holds timber rights in perpetuity on a property and the fee holder has no control over the management of the timber, it would not seem reasonable to define both the fee holder and the timber rights holder as the "forest owner" collectively as currently drafted. Modify section 95802(a)(75) as follows:

In some cases, one entity may be the owner in fee while another entity may have an interest in the trees or the timber on the property, in which case all entities or individuals with interest in the property are collectively considered the forest owners, unless the

<u>owner of the interest in the trees or the timber on the property owns that right in perpetuity and may manage said timber in its sole discretion</u>. (SHILLINGLAW1)

Comment: The definition of "forest owner" in the proposed regulation (section 95802(75)) states that both the holder of timber rights and the landowner are accountable for project reversals. See also Forest Protocol at 6 (stating that "all Forest Owner(s) are ultimately responsible for all forest project commitments"). Land ownership is composed of a "bundle of sticks" and each stick can be separated from the bundle and held by a different person or entity. Accordingly, not all fee title owners of forest land or woodlots will own the timber and/or carbon rights. Since timber rights and carbon rights can be held as a separate property right from fee title to land, the landowner without timber or carbon rights has no legal ability to control forest project activities, and therefore should not be held accountable for forest project commitments associated with timber or carbon rights. This is consistent with ARB's decision, which we support, to forgo landowner agreements such as the Project Implementation Agreement required under the CAR protocol. However, ARB does not address these issues in its rulemaking materials (see, e.g., ISOR IX-1). Any contractual relationship with ARB should be with the party that owns the carbon and/or timber rights. Similarly, liability for reversals should lie clearly with the holder of the carbon and/or timber rights and not extend to a fee owner without such rights. Accordingly we recommend that the definition of forest owner be amended so that the entity holding carbon rights can be defined as a forest owner where ownership is separated. (FCC, BLUESOURCE)

Comment: The definition of forest owner states that both the holder of timber rights and the landowner are accountable for reversals. Since timber rights are a wholly separate property right from the land, the landowner should not be held accountable for reversal associated with timber rights. A landowner does not have any management control over timber rights, nor does he share in any income associated with the harvest of timber or the sequestration of carbon. We recommend the definition be amended so that a perpetuity timber rights owner with 100 percent of managerial control and ownership of the timber assets can be defined as a "forest owner." (NISSENBAUM)

> **Response**: We clarified the definition of "Forest Owner" to designate owners of "real" property in the forest as forest owners. In some cases, this could be the fee holder or timber rights holder. When designating one forest owner for purposes of the offset project operator, the parties may specify in external contracts who has liability for certain parts of the project implementation. We are leaving the specific designation of roles and responsibilities up to the private parties with interests in the forest project, land, or rights. We believe that it is important for the definition of a forest owner to be as broad and inclusive as possible, to capture any entity with an interest in the property involved in the forest project. Aspects of a Forest Project such as soil carbon which is included as a required pool in the case of intensive site preparation, may extend beyond the scope of timber rights. Entities that have ownership of non-timber rights within the project area likely will have some control over activities that may affect forest management or carbon sequestration. Currently, there is no legal

framework to specifically address carbon rights, although we are aware that this question is actively being researched. Given all the potential variables and entities that may share ownership or an interest in the property, we believe the most reasonable and comprehensive approach is to have a single forest owner designated as the Offset Project Operator, that will have the primary responsibility for managing the forest project in conformance with the protocol and the regulation, while all forest owner(s) will still share responsibility for all commitments associated with the forest offset project. The forest owner(s) may define in private contracts any specific roles and responsibilities for implementing a forest offset project.

G-19. Comment: A "first deliverer of electricity" is defined in the proposed regulation as a generator or an "electricity importer" and the "electricity importer" is defined as the entity that takes receipt at a point located outside the state of California. However, these definitions do not account for a situation in which an importer takes title to power at the California border, which is a common practice in the wholesale marketplace. PacifiCorp recommends that ARB specifically account for this situation by defining the "electricity importer" as the entity purchasing the power and delivering it into California. (PACIFICOR1)

Response: Reading of section 95802(b)(84) shows that the commenter is in error regarding the definition of "Electricity Importer." If the transfer of electricity occurs between balancing authorities, the importer is the purchasing-selling entity (PSE) that is identified on the segment of the e-tag that has the first Point of Delivery in California. Otherwise, the importer is simply "the marketer or retail provider that holds title to the electricity," per the definition.

G-20. (multiple comments)
Comment: The definition of "imported electricity" should be amended. The final sentence of the definition of "imported electricity" in section 95802(a)(97) (p. A-20) excludes electricity that is wheeled through California. Section 95802(a)(97) defines "electricity wheeled through California" as being "electricity that is delivered into California with final point of delivery outside of California." "Electricity wheeled through California" is also defined in section 95102(a)(104) of the revised MRR. SCPPA's comments on the revised MRR will propose a change to that definition to include simultaneous electricity exchanges. For consistency, the Cap and Trade Regulation should refer to the definition in the revised MRR rather than including a slightly different definition of the same term. In addition, electricity that is imported into California from a linked jurisdiction should be excluded from the definition of "imported electricity." Insofar as the emissions associated with electricity that is imported into California from a linked jurisdiction would not be included in a California covered entity's compliance obligation, that electricity should not be considered to be imported electricity.

Modify section 95802(a)(97) as follows:

> “Imported electricity” means electricity generated outside the state of California and delivered to serve load inside California. ... Imported electricity does not include electricity wheeled through California, as defined in MRR section 95102(a)(104)~~which is electricity that is delivered into California with final point of delivery outside California~~. Imported electricity also excludes electricity imported into California from a jurisdiction in which a GHG emissions trading system has been approved for linkage by the Board pursuant to subarticle 12. (SCPPA1)

Comment: The definition of imported electricity does not address potential linkages to other external emissions trading systems (ETS). LADWP understands that next year will commence a separate proceeding to address such linkages. The emissions attributed to another linked jurisdiction are already regulated by the other jurisdiction and therefore should be netted out from any compliance obligation that results from the reporting of emissions under AB 32. To avoid double-counting emissions, modify the definition of imported electricity as follows:

> “Imported electricity” means electricity generated outside the state of California and delivered to serve load inside California. Imported electricity includes electricity delivered from a point of receipt located outside the state of California, to the first point of delivery inside the state of California, having a final point of delivery in California. Imported electricity includes electricity imported into California over a multi-jurisdictional retail provider's transmission and distribution system, or electricity imported into California over a balancing authority's transmission and distribution system. Imported electricity includes electricity that is a result of cogeneration outside of California. Imported electricity does not include electricity wheeled through California, which is electricity that is delivered into California with final point of delivery outside California. Imported electricity does not include electricity that is imported from a source in an approved external ETS where emissions associated with that electricity are attributed to and regulated by the other linked external emissions trading system. (LADWP1)

Comment: The definition of imported electricity excludes electricity wheeled through California, which is electricity that is delivered into California with final point of delivery outside California. To remain consistent with treatment of simultaneous energy exchanges under the AB 32 fee regulation, modify the definition of imported electricity as follows:

> "Imported electricity” means electricity generated outside the state of California and delivered to serve load inside California. Imported electricity includes electricity delivered from a point of receipt located outside the state of California, to the first point of delivery inside the state of California, having a final point of delivery in California. Imported electricity includes electricity imported into California over a multi-jurisdictional retail provider's transmission and distribution system, or electricity imported into California over a balancing authority's transmission and distribution system. Imported electricity includes electricity that is a result of cogeneration outside of California. Imported electricity does not

include electricity wheeled through California, <u>including simultaneous exchanges</u>, which is electricity that is delivered into California with final point of delivery outside California, <u>including simultaneous energy exchanges in which the point of receipt and point of delivery are outside California.</u> (LADWP1)

Response: While we did not modify the definition of “Imported Electricity” as requested, we did include language in section 95852(b) that defines the compliance obligation for first deliverers of electricity and excludes qualified exports from the compliance obligation. We also added a new definition for qualified exports in section 95802(225). Allowing the exclusion of qualified exports has the same effect as excluding simultaneous exchanges. Also, the regulation clearly states that a first deliverer’s compliance obligation is for “emissions in California or in a jurisdiction where a GHG emissions trading system has not been approved for linkage by the Board pursuant to subarticle 12.” Furthermore, we modified section 95852(b) to also include a description of the calculation of the compliance obligation ($CO_2e_{covered}$). Finally, the cap-and-trade and the MRR definitions remain consistent on this subject.

G-21. Comment: Metropolitan acknowledges that the definition of electricity importer covers both marketers and retail providers, and that the current proposed definition of marketers covers Metropolitan. However, Metropolitan is not a true marketer of electricity, as the term is typically used. Metropolitan only imports energy for the purpose of serving its own load on the CRA and not to "market" or resell this energy. Modify Section 95802(a)(113) as follows:

(113) "Marketer means a purchasing-selling entity that takes title to wholesale electricity <u>for the purpose of resale</u> and is not a retail provider.”

This change would clarify that Metropolitan is not intended to be included in the Cap-and-Trade Program. However, this modification would not affect the inclusion of the other entities that we have identified for coverage under the regulation, nor would it impact the requirements that apply to these covered entities. (MWDSC1, MWDSC2)

Response: We do not agree with the proposed change Metropolitan suggests. It is our intent to include all emissions from electricity imported into the State of California. This would include the electricity that Metropolitan imports to operate their pumps to move Colorado River Aqueduct (CRA) water.

G-22. Comment: The definitions for “Electricity Importers” and “Purchasing-Selling Entity” should be clarified to distinguish the purchaser-seller from the source/sink, and to account for deliveries at the California border.

E-tags and e-tag data simply do not offer the tracing mechanisms and delivery information that the proposed regulations would use to define “Electricity Importers.” Defining electricity imports has been a challenging issue in multiple proceedings before the CPUC, the California Energy Commission (“CEC”) and other agencies. Here, as in other proceedings, care is needed to ensure that ARB obtains the necessary level of specificity in its regulatory definitions to allow for distinctions among different commercial circumstances in the power markets, and not rely on e-tags for sufficient data. The definitions for “Electricity Importers” and “Purchasing-Selling Entity” do not distinguish the purchaser/seller entity as that term is used on e-tags from the source or sink of the electricity, or from the purchaser and seller, or importer and exporter, of the electricity. Often times, a North American Electric Reliability Corporation (“NERC”) e-tag identifies an out-of-state balancing authority, but not the resource or resource type that is the source of the generation, even though that balancing authority (or owner of the resource that is the source of generation) is not the entity selling or importing the power. (PACIFICOR1)

> **Response:** We have relied upon the resources and references provided by NERC, and have coordinated terms used in the regulation with NERC terms and tagging requirements. NERC is the entity responsible for managing the e-tag system and setting rules and procedures for the use of e-tags. The California Independent System Operator Corporation (CAISO) sets tariffs, rules, and policies for how e-tags are used specifically within the CAISO market and system under the NERC umbrella. We use the NERC-approved definition of PSE, but add that the PSE is identified on a NERC e-Tag for each physical path segment, which is an additional requirement for e-Tags. The terms “sources” and “sinks” are not precisely defined, but in general they correspond to points of delivery, not entities that deliver electricity. PSEs are entities (electricity importers) that schedule and deliver electricity. We use e-Tags to establish the identity of the first deliverer for imported electricity when the electricity is required to be scheduled with an e-Tag. E-Tags are required for electricity transfers between balancing authorities. For other types of deliveries of electricity to California, we use other data to establish the identity of the first deliverer.
>
> We modified section 95852, and we require other information related to ownership or contracts for electricity, in addition to e-Tag data. The additional information assists in identifying the first deliverer and ensuring that specified imports are properly identified. We agree that often e-tags identify the balancing authority as a source rather than a generator. That is why we do not rely solely on e-tags in the new requirements (section 95852(b)(2)) for electricity importers to calculate compliance obligations based on a facility-specific emission factor. We note that “Electricity Importers” are defined as marketers and retail providers that hold title to imported electricity. We continue to work with stakeholders to clarify how electricity importers are identified in the regulation.

G-23. Comment: While e-tags may in some cases provide reliable evidence regarding imports, e-tag data should not be relied upon in isolation for tracking imported power. Therefore, PacifiCorp suggests that ARB revise the definitions in the proposed regulation to use the actual act of electricity import into California as the primary basis for identifying the “first deliverer of electricity.” Given that e-tags cannot automatically provide the data being sought in the proposed regulation, self-reporting by the importer will be required. (PACIFICOR1)

> **Response:** We agree that e-tags cannot be solely relied upon for tracking imported electricity. We added a definition of "Direct Delivery of Electricity" (section 95802(b)(68) that lists other ways of importing electricity. This definition is also explained in the MRR, and the use of these ways in determining first deliveries for specified power is in MRR section 95811.

G-24. Comment: Calpine proposes the following revisions, which are largely based upon the provisions concerning long-term contract generators appearing within proposed federal climate change legislation and regulations implementing RGGI. Modify section 95802(a) as follows:

<u>(111) "Long Term Contract" means a sales or tolling agreement governing the sale of electricity and/or useful thermal energy from an electric generating facility or cogeneration facility at a price (whether a fixed price or price formula) that does not allow for recovery of the costs of compliance with this regulation and that is at least five (5) years in duration, provided that such agreements are not between entities that were affiliates of one another at the time at which the agreement(s) were entered into.</u>

<u>(112) "Long-Term Contract Generator" means a covered entity which is not an electric distribution utility and which operates an electric generating facility or cogeneration facility pursuant to one or more long-term contracts.</u>
(CALPINE1, CALPINE2

> **Response:** We appreciate the comments and input from Calpine regarding the definition of "Long Term Contract." At this time, we do not want to interfere in the potential renegotiation of these contracts that are based on a fixed price. We hope that parties will continue the negotiation process, or that parties continue to investigate alternative fuel options, which emit fewer GHGs when combusted.

G-25. (multiple comments)
Comment: In the proposed regulation "Electrical distribution utility(ies)" means an Investor Owned Utility (IOU) as defined in the Public Utilities Code section and 218, or a local publicly owned electric utility (POU) as defined in Public Utilities Code section 224.3, that provides electricity to retail end users in California." This definition does not include a category of electric providers that are similarly situated to IOUs and POUs; Electrical Cooperatives. Electrical Cooperatives are defined in Public Utilities Code section 2776 as "any private corporation or association organized for the purposes of transmitting or distributing electricity exclusively to its stockholders or members at cost." As such, Electrical Cooperatives are a "hybrid" between a POU and IOU, in that they are owned by their members, but operate as a non-profit public service for end use members. Electrical Cooperatives in California are small utilities located in rural areas, facing high infrastructure costs and other obstacles as they strive to provide affordable and reliable electric service to their members. As non-profit, member-owned utilities

governed by their locally-elected boards of directors, they must adhere to federal Rural Utility Service (RUS) guidelines, but are also subject to many of the same AB 32 mandates as IOUs and POUs.

NCPA recommends that the proposed regulation be revised to provide that Electrical Cooperatives be included in the definition of “Electrical distribution utility(ies)”, and that those Electrical Cooperatives that serve retail customers be eligible to receive electric sector free allowances. Including this small group of utilities within the definition of “Electrical distribution utility(ies)” would not change the scope of the program, nor have an impact on the recent discussions regarding allocation of allowances to the electricity sector, and data from the Electrical Cooperatives should already be part of 89 million allowances available for allocation to electrical distribution utilities. In section 95892, the proposed regulation specifically addresses the need to allocate allowances to Electrical Distribution Utilities “for the protection of electricity ratepayers.” Electrical Cooperatives have electricity ratepayers, the same as all other Electrical Distribution Companies. However, unlike energy service providers, electrical cooperatives provide more than just the electricity transaction to their customers, therefore making them analogous to IOUs and POUs for the purposes of the proposed regulation. If the definition of “Electrical distribution utility(ies)” is not changed as described above to include the Electrical Cooperatives, the ratepayers of these entities will bear the total cost of the cap-and-trade regulation. Accordingly, modify section 95802 (a)(57) as follows:

“Electrical distribution utility(ies)” means an Investor Owned Utility (IOU) as defined in the Public Utilities Code section and 218, or a local publicly owned electric utility (POU) as defined in Public Utilities Code section 224.3, <u>or an Electrical Cooperative as defined in Public Utilities Code section 2776</u>, that provides electricity to retail end users in California. (NCPA1)

Comment: In the proposed regulation, “Electrical distribution utility(ies)” means an Investor Owned Utility (IOU) as defined in the Public Utilities Code section 218, or a local publicly owned electric utility (POU) as defined in Public Utilities Code section 224.3, that provides electricity to retail end users in California." (section 95802(a)(57)). The title "California retail end users" is synonymous with "California ratepayers." The proposed definition incorrectly fails to include Electrical Cooperatives. Electrical Cooperatives are a category of electricity providers that are similarly situated to IOUs and POUs, in that Electrical Cooperatives also provide electricity to California ratepayers. The only difference is that in an electrical cooperative system, the ratepayers are the ultimate consumer of the electricity provided by the cooperative distribution entity (such as Anza), which distributes the electricity at cost to its rural service area. AEPCO recommends that the proposed regulation be revised to include Electrical Cooperatives in the definition of section 95802(a)(57) and like POUs and IOUs, be eligible to receive electric sector free allowances. If the definition in section 95802(a)(57) is not changed to include the Electrical Cooperatives, the ratepayers of these entities will bear the total cost of the cap-and-trade regulation. Modify section 95802 (a)(57) as follows:

"Electrical distribution utility(ies)" means an Investor Owned Utility (IOU) as defined in the Public Utilities Code section 218; a local publicly owned electric utility (POU) as defined in Public Utilities Code section 224.3; <u>or an Electrical Cooperative as defined in Public Utilities Code section 2776</u> that provides electricity to retail end users in California. (AEPC)

> **Response:** We agree, and modified the definition to include electrical cooperatives as defined in Public Utilities Code section 2776.

H. ECONOMIC IMPACTS

This section includes comments and responses about both the Economic Analysis (Appendix N) contained within the Staff Report and general concerns about the potential impact of the regulation on California's economy and businesses. Major sub-topics include effects on small businesses and agriculture, timing of the start of the program relative to the economic recession, ability of covered entities to pass-through the price of allowances to their customers, and support for and opposition to the program.

General Concerns: Cost, Price Increase, and Economy

H-1. (multiple comments)
Comment: I do not want implementation of a CA cap and trade system. There is no environmental benefit for such localized action, and the program will increase food and energy costs. This is a waste of taxpayer money. (MCCARTHYV)

Comment: Cap and trade will raise our gas prices, destroy jobs and shut down California farms. Please note that myself, my friends, and family are against any representative or organization attempting to implement cap and trade, and you will not receive our support. (ATP)

Comment: This proposed regulation will drastically raise costs on a myriad of products. The improvement to weather and air quality brought about by this measure is miniscule. It would, however, "even the business playing field" with products that are made in countries like France that already have this policy. So I wonder if it is a political method of lowering our productivity in the global marketplace. All in all, it is a bad idea for America. (COCLRAN)

Comment: If you want California to keep sliding into the financial abyss, Cap and Trade is the way to do it. (WOODWARD)

Comment: Please do not vote for or pass the cap and trade bill. We will be watching and keeping track of who is responsible for raising our utility bills and will respond on election day if not before. (SCHLICHTER)

Comment: I do not support CARB's wish to impose Cap and Trade in this state. We do not need any further cost burden placed on the people of this state. (CROULET)

Comment: Do not implement AB 32 and or cap and trade. California's economy is devastated from over taxation and regulation. (WESSELS)

Comment: The proposed adoption of a California cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms Regulations will further jeopardize the already failing California's agricultural and business economy. The people of this state do not want this regulation. Please do not adopt it. (LUCE)

Comment: Please do not implement these caps. Our State's economy is already hurting enough. (RANDALL)

Comment: I do not support this move to legislate a proposed California cap on Greenhouse Gas Emissions. I believe it is misguided and will cause unintended financial consequences to the fiscal health of the state. (HARRISS)

Comment: In one of the worst economic periods in our history, this is an inappropriate time to implement any regulations. Please slow down and take cap and trade regulations off the table. (FRENCH)

Comment: We cannot afford Cap and Trade. I am very worried about the direction this state and country are going. (CAMPRINI)

Comment: I wanted to post my objection to the pending regulations. Californians are going to be outraged should these measures be enforced. I don't know anyone who is not suffering financially due to the economic conditions. (BROWNE)

Comment: At a time when our state is billions in the red, now is not the time for any cap on greenhouse gases or any regulation such as those. (LUEKENS)

Comment: Gas prices now are higher than ever, and raising gas prices will only hurt everyone who drives to and from work, buys food for family, and I guess you can forget vacations. (JAMES)

Comment: Your cap and trade energy tax proposal scheme will increase gas prices, cost jobs, shut down family farms, and make food more expensive. (PINKSTON2)

Comment: I hope you will be reasonable, that is come up with a balance which advances the environment but doesn't stifle enterprise in California. (AVW)

Comment: Estimated costs for this proposed trading scheme before you, according to a report compiled by free market proponent Calwatchdog.org, the potential cost per household ranges from $570 to $6,500 annually, and the price of gasoline would increase 61 cents per gallon by January. Some of the unintended consequences likely to result from this rule could be massive increase in harvesting of lumber in sensitive sites and selling back credits to California resulting in a double fee for commodity lumber, still more transfer of wealth from an already impoverished California citizenry and the devastation of precious habitat to countless endangered species of plants and animals. (HASSEBROCK1)

Comment: Cap and trade means cap and tax. The Federal Government and many States have "backed off" on cap and trade. California should not proceed with this job killer. (HILLG3)

Comment: Cap and trade will utterly destroy the economy of California, worse than it is now. (BLAKEMORE)

Comment: California is flat broke. Our State economy is in complete shambles and we have the worst business climate of any state in the union. Companies are leaving the State in droves and new startups are scarcer than ice cream cones in the Sahara. A costly cap and trade program may push us beyond any hope of significant recovery. (MYERSG1)

Comment: I am strongly opposed to the passage of this program. The cost of this program to our economic wellbeing far exceeds any benefits we may reap from it. If so many other states have pulled out, why should we continue down the road to economic disaster? Please do not vote to adopt the Cap and Trade program. (SIEBERN)

Comment: This will not only affect the farmers in our state, but the cost of foods for everyone. Are you trying to move agriculture out of the country? You have the power to extensively damage lives of many people, forever changing our ability to compete and produce food, all because you are still drinking the cool-aid professional illusionist Al Gore gave you. Wake up; get real; be a hero; do not let this happen! (STEWARTM2)

Comment: It should be clear by now that California is teetering on the edge financially, that people are moving away in droves, costs of everything are going up and we are driving away the job producers. To be kind I am calling these "cap and tax" ideas misguided, but my heart tells me that there are people who want to see our State and our country fail and collapse. (AGEE)

Comment: By issuing mandates, the Board is not relying on the market, but creating ways to destroy the free market and create totalitarian economic controls over the energy sector of our economy. Any attempt to implement caps on greenhouse gas emissions is in direct opposition to capitalism and the economic structure that creates wealth in this country. It will cause massive budget deficits, high taxes, and complete economic depression. (NARITELLI)

Comment: The American Chronicle article entitled “Cap-and-Trade Energy Tax will Cause Redistribution of Wealth Among States and Working Families” cites the Congressional Budget Office as stating that cap and trade would cost the average American household an extra $1,600 per year. It would increase the price for a gallon of gasoline between $0.61–$2.53, and would increase electricity costs anywhere from 44–129 percent. You guys must have dollar signs in your eyes or someone else does and they are using you as a front! (LAFOLLETTE)

Comment: The economic analysis that was conducted for the Cap-and-Trade program was completed only at a macroeconomic level and failed to analyze the costs of the individual facilities costs in complying with the program. The proposed program will lead to hundreds of thousands of increased annual cost just to continue operating in

California. Statewide allowance cost will be anywhere from $3 billion to $73 billion annually in increased cost to affected entities. (AGCOALITION)

Comment: Please disregard the Cap and Trade rulings. This will add even more burden on the weak economy and working people. We cannot afford more taxes to support this legislation, which is based on questionable research data. (RITCHIEC)

Comment: Environmental regulation needs to be throttled back primarily because it has crippled private enterprise throughout the state. Business has vacated at an alarming rate which equates to job loss which equates to loss of state revenue which will multiply the state deficit. Your "Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms Regulation, Including Compliance Offset Protocols" will serve to vacate more revenue. When will you understand this will bankrupt California for an incomplete science that limits and punishes prosperity? (ARTENO)

Comment: I'm particularly worried about cap and trade because it's clear there will be much higher energy prices and that businesses will be passing those prices on to their customers. The Legislative Analyst has reported that unless other states adopt climate change laws as strict as California's our state will lose businesses, jobs and economic activity. I'm in a green business and I'm a green supporter. But I may turn out to be one of those businesses the Legislative Analyst was talking about. One of the sad ironies of cap and trade and other AB 32 policies is that it will cost so much it will drive a lot of folks who want to engage in the green economy to other states. I haven't seen anything in this proposal that convinces me this will not be the case. Even with a phased-in approach to selling allowances, with the economy the way it is and with the recession predicted to continue for several years, I'm hoping you will direct your staff to do some more research into how the costs and benefits are likely to line up in real time, and to come up with a realistic plan on how to control those costs. (AWSINC)

Comment: What good can come out of this at a time when people are struggling to keep or maybe find employment and then this law makes it three times harder for employers to hire, or employees trying to get to a job? (STEELER)

Comment: The current proposals for cap and trade will raise the costs for average working families here in California. This is the most trying time for us financially, to add to that burden will put many over the poverty line. Increases on heating and cooling bills, gas, food, etc. are avoidable. There must be an alternative, such as giving tax breaks to companies that choose to cut their carbon emissions. Please consider the many struggling families before imposing further taxes upon us. (HAMMOND)

Comment: Your proposed action would result in widespread misery to the poor. (POLLOCK)

Comment: We can't afford the kind of compliance regulations that you want to impose. Out of state companies will simply cease doing business with us. (SAMARDICH)

Comment: I do not want cap and trade. It would be a bad law, and discourage and harm businesses, and is wrong! Do not consider the adoption of a cap on greenhouse gas emissions and market-based compliance mechanisms! It will kill what is left of California business, and hurt taxpayers. (KYLBERG)

Comment: Cap and Trade will basically add costs of operation to businesses in California and restrict industrial growth. This will increase costs of all goods and services that require energy to produce. This is an added burden that Californians can ill afford especially when the unemployment rate is at 12.5 percent. The increased cost of Cap and Trade will disrupt the state economy and stop recovery from the current recession. The Cap and Trade plan is being pushed by financial interests that see a new market place for them to buy and sell commodities. This will generate huge windfall profits for the commodity traders. There has been inadequate consideration given to the impact this new added cost will have on the economy of the state. (JEPSON)

Comment: California's businesses are already overtaxed and overregulated. They are fighting for survival now. Who will be left to pay the taxes if they close their doors? (SELLERS)

Comment: I'm having a hard time understanding how rising energy is not going to affect the economy and other individuals who are having a hard time. Most people are living paycheck to paycheck and in some instances they're living off of unemployment benefits. These folks can't afford higher utility bills. And they can't afford to make investments in new cars, refrigerators, or solar roofs, even though that there's rebates associated to this. From what I see, the staff answer to just about every concern about the cost is saving energy efficiency. It seems to me that California's economy is going to get better but not yet. This is something else that I'm having a hard time understanding, the timing of this proposition. (RAMIREZJ)

Comment: We're very concerned that the higher energy costs predicted as a result of cap and trade will create severe hardships for California families and for veterans in particular. Higher energy costs translate to lost jobs, a scenario that we can't afford to risk. The challenges facing our veterans are even greater than those that face our civilians. The U.S. Bureau of Labor Statistics reports that about 21 percent of Gulf War veterans serving after August 2001 reported having a service-connected disability and 21.6 percent of 18 to 24-year-old male veterans for that period were unemployed as of 2009. With so few jobs to go around, it's getting harder and harder for veterans like these to find work. We must not make it even harder than it already is. I understand the concept of higher energy costs potentially being offset by energy savings. But we're talking about people who can't afford to pay their utility bills as it is and who can't afford to buy new energy efficient cars and refrigerators. The staff's conclusion that the cap and trade program will not negatively impact jobs and the economy is frankly not realistic. We hope you will take this into account before pulling the switch on a plan that has the potential to hurt those least able to afford it. (AGIF2)

Comment: We're concerned with the increased costs of the program. We are going to be the ones that are going to pay the high cost of the energy, fertilizer, and higher water cost delivery. We are the end users, and are going to be the ones heavily burdened. So we ask that cost implications be recognized and also for a panel to be set up to monitor these kinds of costs and ag have a seat at the table because we're the ones paying the bill. So hopefully we can be a part of the panel. (CCGG)

Comment: While we applaud the goals of your cap and trade proposal, we're concerned that this policy may indeed put jobs and family projects budget at risk. All indications are that this cap and trade program will drive energy costs up for businesses for families. When businesses have to pay higher energy costs, they have less money available for payroll; and that means a reduction in jobs and in the critically important benefits like health care that go with them. This is very, very serious for all Californians but especially for our veterans, who already suffer from disproportionately high unemployment. They face special challenges in civilian market. Their military skills do not always translate directly to civilian jobs. And while the government, the VA, does all it can, there are not enough resources to give our veterans the support and training they need to transition to civilian life. In California, those resources will become even more strained as local governments and nonprofits alike suffer from cap and trade higher energy costs and the reduced tax revenues that will result as the economic activity is reduced. The staff's assumption that cap and trade would not cost anything is not supported by credible facts. Therefore, proceeding further, more work is necessary to ensure we avoid unintended consequences that can make it even harder for our veterans and families and other Californians. Please consider this when deliberating your next step in this case. (AGIF1)

Comment: I've heard a lot of different sections of industry speak today. One thing that ties us all together is that we are all consumers. If we just take into account that we shop at, let's say, five businesses apiece, if each one of those businesses costs do go up, they have no choice in order to continue to operate but to pass those costs on to you and myself. Multiply that times however many businesses we frequent, and you can see that it becomes quite an issue for families that are living paycheck to paycheck, single family incomes with children that are trying to save for college, that are trying to live a traditional wholesome and productive lifestyle. (RAMIREZA)

Comment: I'm extremely worried that the action you're about to take on cap and trade will have direct and detrimental impact on my business. The stated purpose of this cap and trade program is to impose costs that induce people to invest in newer, more energy efficient devices. When cap and trade forces the cost of fuels and vehicles to go up, the value of most vehicles will go down. That means that cars and trucks in California, currently own and drive will be worth a lot less. My inventory will be worth less as well. In my neighborhood and many others like it people can't afford new cars. They can't afford higher gas prices. Many of them can't even afford to take the bus nowadays. With the economy as bad as it is, people are already holding on to their old cars longer. Under cap and trade, they are likely to keep them even longer, which means no reduction in emissions and a lot less business for most car lots. We will all suffer. So it's somewhat naive to say that it's okay for energy prices to go up because people will make smart investments in new cars and other things and save on energy in the long run. We're in a major recession and unemployment is sky high, especially in California. The people who can't afford those decisions far outnumber the people who can. What I'd like to know is, what are you going to do when these assumed investments in energy efficient cars and other things don't happen and when you're not meeting your carbon reduction goals? Are you going to make the energy we use and need every day even more expensive? Frankly, this plan seems more like punishment than inducement. (DELACRUZ)

Comment: I am skeptical of the ARB's economic analysis of the Cap-and-Trade program, which suggests that there will be very little cost to the overwhelming benefits. However, the authors of the analysis do reluctantly acknowledge that the program will create an adverse economic impact: the gross state product will be reduced; the costs of business will rise; and the economy's recovery will remain stagnant. In order to operate well, our state relies on a thriving business climate. Given California's $26 billion deficit and the 12.4 percent unemployment, our state's economy is not stable enough to implement AB 32's policies that we know will further burden business. (LAMALFA)

Comment: ARB makes a number of seemingly contradictory economic claims. The ARB states that its cap-and-trade regulations will reduce the growth rate of the California economy from 2.4 percent to 2.3 percent. At the same time, the ARB claims that the regulations under consideration will "not have a significant statewide adverse economic impact directly affecting businesses, and little or no impact on the ability of California businesses to compete with businesses in other states." And that, "impacts on long-term projected growth rates in personal income and employment are similarly small." And that, "Regulated businesses may face additional indirect costs due to increased energy and input prices, and some businesses might be impacted based on the compliance path they choose to meet their obligations under the proposed regulation." And that, the "proposed regulatory action would not eliminate existing businesses within the State of California, but would affect the creation of new businesses or the expansion of existing businesses currently doing business in California. The proposed regulatory action would not eliminate jobs within the State of California, but would affect the creation of jobs within California." It strains credulity to believe that California can act to completely reorder the energy sector and only slightly reduce economic growth, slightly increase prices and end up with more jobs, not less. Assuming this to be the case, does that mean that the ARB projects more lower paying jobs and relatively less higher paying jobs as the result of its actions? How else can a reduction of economic growth be explained as part of the ARB analysis? Lastly, ARB, in its economic analysis states that the analysis did "not consider the avoided costs of inaction. The potential effects of climate change that are expected to occur in California, such as increased water scarcity, reduced crop yield, sea level rise, and increased incidence of wildfires, could cause severe economic impacts." Given that California's cap-and-trade efforts, when viewed in the global context of a developing China and India, is likely to provide, at most, a day or two's reduction in greenhouse gas

(GHG) emissions (and this is assuming that leakage doesn't accelerate, as more economic activity that once occurred in California is off-shored to coal-fired China), how can this statement even be seriously countenanced when, in fact, there will be no significant global GHG emissions reduction as a result of the ARB's actions? Lastly, over the past 150 years, California has experienced "increased water scarcity, reduced crop yield, sea level rise, and increased incidence of wildfires" with three of the four directly attributable to environmental policies that have limited water storage and conveyance (increased water scarcity), cut flows of water to farms (reduced crop yield), and reduced timber harvesting and forest fuel management (increased incidence of wildfires) – the one foot rise in sea level over the past 150 years being the sole impact not caused by environmental policy, and certainly not an impact anyone in California has seen as particularly difficult in which to adapt. (ASMMANDEVORE4)

Comment: We're extremely disappointed with the economic analysis of the proposal. It's only 20 pages long and certainly not very robust and not at the level that we're used to when we look at rate making and impacts that we look at the Commission. We're also very skeptical that the impacts on the price of electricity to consumers is anywhere near as modest as the economic analysis, as bare as it is, proposes. Energy prices for the farming community have risen approximately 40 percent in the last decade. Largely that was due to poor policymaking through the deregulation debacle back of the 1990's. And so you can understand our concern and our hesitancy a little bit about this potential cost impacts that a proposal just like this will have without having a robust understanding behind it. Since deregulation, the cost of the actual commodity of electricity, where this proposal will have its main impacts for our members, is a pass-through cost for the utilities. And at this point we see that the utilities have a little bit of exposure in terms of the pass-through costs that they're going to pass on to the customers. A lot of the risk of this is coming down on the ratepayers - our family farms, our agri-businesses. And that's going to come out in the form of higher energy costs. We're concerned about that, because in the 1980's when we had a lot of high energy cost and it started going up, a lot of those agricultural customers moved to diesel and moved off of electricity, which I think is the opposite direction that we would like to see in the movement in the spirit of what this proposal offers. We look forward to continue to work with the Board on this proposal as it moves forward, and assist as we can to help make this economic analysis more robust. (AGECASSOC)

Comment: The proposed rule fails to implement the key elements of successful cap-and-trade programs, and imposes unnecessary costs upon the California economy that could be truly debilitating. The economic analysis performed with respect to the Proposed Program does not seem to appreciate the likely market responses to the Proposed Rule, and seems to make unsupported and optimistic assumptions about market responses to cap and trade regulation. Moreover, key aspects of the existing market for CO_2e emitting industries and businesses are not accurately assessed or incorporated into the analysis. (HOR)

Comment: Please do not go forward with your push on cap and trade. California cannot afford the loss of jobs and tax base that this would affect. (ROBERTSK)

Comment: Cap and trade means cap and tax. The Federal Government and many states have backed off on cap and trade. California should not want to proceed with this devastating job killer. (HILLG2)

Comment: CARB should stop this unethical, cost-raising, and job killing attempt immediately. (BABIGIAN)

Comment: I am strongly opposed to a cap on greenhouse gas emissions. It's a job killer. (PAPPANO)

Comment: ConocoPhillips supports the development of federal climate change policy in the United States that is economically efficient, environmentally effective and that ensures the availability of secure, affordable and reliable energy. We oppose development of a patchwork of state-level programs. California's stand-alone actions on climate change will have a very negative impact on ConocoPhillips' operations in the State. The cost impacts will be significant and, depending on market reactions, may necessitate reduced operations that impact jobs and potentially increase the State's dependence on gasoline and diesel imports. (CONOCO)

Comment: Enough with the stifling effects of California government on business. We don't need a cap on greenhouse gas laws now too. Please consider this a big vote against instituting another law to kill business in my home state over the theory of global warming. (BEAVER)

Comment: The proposed California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms Regulation, if adopted, will introduce a crippling and devastating dismantling of California's agricultural and business economy. If your goal is to drive California backward to the economic and social status of a third world country, you could not choose a more effective means than the adoption of this regulation. With functional unemployment in California hovering just below 20 percent, business owners, the greatest jobs generating engine in the state, ask you not to adopt this regulation. (BROESAMLE)

Comment: These costly measures will have absolutely no impact on global warming and will result in even more California job losses which we can ill afford. (STARNES)

Comment: No to cap and trade. We cannot afford to lose any more businesses in California. If we don't have jobs, we won't have anything to tax. (HILLG1)

Comment: The proposed rule radically skews the economic burdens on different segments of the California economy. (HOR)

Comment: The "cap and trade" scheme you will be proposing will put California at a huge disadvantage commercially with competitors, further driving business and agriculture from the State. (BROWNT)

Comment: I adamantly oppose the statewide cap and trade scheme that will raise our gas prices, kill jobs and shut down farms. (BRUEGEMAN)

Comment: Cap and Trade will further hurt California's economy, driving business and industry out of California and into states and countries that do not have California's regulations, China having virtually no environmental regulation at all. Considering California gets 25 percent of our pollution from China, how exactly does California benefit from Cap and Trade? (JENKINS)

Comment: This action is a job killer and with only California in the game it is a total waste of capital. More jobs will go out of state. More businesses will go out of state. Look what this will do to making the California budget harder to close. (GATES)

Comment: Extra cost imposed by this program here in California will have a series of implications for California businesses. We won't be part of a broader program. Thus, any pain that could potentially come down will put us at a competitive disadvantage to other companies throughout the country. (CALCHAMBER2)

Comment: Just the government oversight of this policy is a mind boggling cost of tax dollars and human resources. For every green job 'created' how many other jobs will be lost by the extra burden on other businesses? How many businesses will move out of California due to this policy. It is already one of the least business friendly states in the union. (PEABODY)

Comment: The proposed cap and tax scheme under consideration is an added burden to the federal proposed greenhouse gas rules (40 CFR Part 98, subpart W) placing California based companies at extreme hardship and a competitive disadvantage. Promulgation of this rule as proposed without assurance from the federal EPA that it would be “treated as equivalents or substitutes” signals to California based companies that investments should be made outside of California. Further, the Western Climate Initiative (WCI), which might provide cover for California’s scheme is falling apart. New Mexico’s political change is ahead of our own and while they have recently passed a rule on the same day that the state elected a Governor that rejects Anthropogenic Global Warming (AGW) and is supported with electoral support that will result in the only state in the WCI that could be counted on to follow us as sure bets to call it off. The other states are all recalcitrant to support their obligations and are now poised to join in a new club with a different motive, to entice those companies that are considering leaving the Golden State to relocate to their own state. (HASSEBROCK1)

> **Response:** We recognize that there will be price increases from the proposed cap-and-trade program. However, we do not believe that these price changes will result in large negative impacts to the state economy. Table N-3 and Table N-7 of the staff report highlight estimated changes in energy prices and resulting economy wide estimates of impact. The estimated impacts show relatively small changes in economic growth and employment when compared to growth

otherwise expected over 2007 to 2020. Please see Chapter VIII and Appendix N of the Staff Report for additional information about our economic analysis of the cap-and-trade regulation.

The cap-and-trade program does not specify how or where emissions reductions will be made. Reductions will be made by covered sources if the cost of making reductions is less than the cost of acquiring allowances, thereby minimizing price increases. Further, free allocation to some covered entities at the beginning of the program will assist with transition and reduce the potential for economic leakage. The regulation is also designed with cost-containment mechanisms such as banking, limited use of offsets, and an allowance price containment reserve.

For non-covered sectors of the economy, individual households and businesses are not expected to make rapid or extreme changes in their purchase decisions of energy-consuming devices (e.g., appliances or automobiles). Devices have useful lifetimes and have to be replaced at some point. The responses to cap-and-trade will be to slightly shorten the useful lifetime of the devices. Therefore, individuals may replace the devices sooner and may choose devices with higher efficiencies than they would have otherwise chosen.

Our economic analysis evaluated the impacts of the regulation on both small businesses and individual consumers. Based on analysis of data from Dun and Bradstreet, we found that the small business sectors with the greatest percentage of their revenues spent on electricity and natural gas were primarily service-related and serve local markets. Out-of-state businesses cannot serve these markets. As a result, most California small businesses are not likely to face competitiveness issues relative to out-of-state businesses. Under the likely range of allowances prices, most small business sectors experience less than a 2 percent change in the share of revenue spent on energy.

There are existing programs that will help households and business identify energy-saving opportunities and provide assistance in making efficiency improvements. Finally, auction revenue could be used to reduce or eliminate negative impacts to most individual households.[2]

Effects on Small Business

H-2. (multiple comments)
Comment: We're very concerned that the cap and trade program you are considering will make it much more difficult for small business and entrepreneurs who are striving to build and maintain businesses here in California to be successful. Regardless of staff's assertion that cap and trade's higher energy costs will be a wash, all indications are that the costs will rise much higher and faster than will any potential future energy efficiency

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[2] http://www.climatechange.ca.gov/eaac/documents/eaac_reports/2010-03-22_EAAC_Allocation_Report_Final.pdf

savings. We've been following the AB 32 process for several years now and have observed the common thread that staff consistently says it's not going to cost anything. Yet experts like the California Legislative Analysts have concluded that there will be costs, especially in the near term, and that those costs are going to have negative impacts. For example, the LAO found that some businesses may not be able to afford AB 32's transition costs and therefore will not be around to enjoy energy savings that might occur later. In another report earlier this year, the LAO determined that California-only policies will have an adverse effect on our state's economy, resulting in lower business profits; higher prices; and reduced production, income, and jobs. Cap and trade is one of the largest policy elements of AB 32. So it stands to reason these findings would apply. There is a reason most other states and the federal government have put cap and trade on hold. There's is reason all but one other state in the Western Climate Initiative have declined to move forward with the cap and trade. (LIFCI)

Comment: I implore you, please do not pass cap and trade regulations. Other states have already abandoned these outlandish measures and for Good reasons. Do likewise. The last thing Californians need is taxes that will result in the loss of millions of jobs. This is not in our best interest! Please listen to the small business owners and those who would like to remain employed - do not pass the cap and trade regulations. Make California business friendly so we can grow our economy. (MURGUIA)

Comment: I would ask that you consider minority and Hispanic small businesses and the impacts of the cap and trade to our communities. We have many trucking companies that will be directly impacted at a time when they as well as all of our small minority businesses are struggling to keep their doors open. I want to remind you that as small business grows, so grows our great state. (SJCHISPCHMBR)

Comment: As a regulated entity, our utility, under cap and trade, LADWP is facing enormous cuts for emission allowances. Now, it sounded like earlier today that you may have come to some type of an agreement with them. We've not privy to that. However, as of yesterday, based on consumption of coal as a source of energy, we were able to realize that the economic analysis ranged in increases from 54 to 269 percent. Between this and the renewable portfolio standard, to say that L.A. ratepayers will be hard hit is a significant understatement. The premise of the allowance fee is that it will allow inducements to cause major emitters to switch to lower Carbon usage and more efficient energy sources. Your staff report also observed that rising energy prices drives purchases of more expensive but more efficient devices. Staff's assumption assumes that this is okay and that there are public initiatives programs available for small businesses will drive small businesses to go for these types of investments. However, we would like to say that small businesses right now are operating in such a narrow margin that they basically don't have the access to capital or the resources that many other industries do have. And so we encourage that a further study be done on the impact of small businesses. (LAHISPCHMBR)

Comment: Care must be taken to ensure that any cap and trade program you adopt does not have a price tag that will put California in a dire economic situation and ultimately doom the policy to failure. As you know, the federal government has decided to postpone action on a national cap and trade policy because the cost to businesses and consumers would be too high. There seems to be a significant disconnect between this conclusion and that of your staff, who project that there will be essentially very little cost. With all due respect, we question this conclusion since the staff's economic analysis projects double digit increases in the cost of the most commonly used energy sources and fuels as a result of cap and trade fees. This doesn't even take into account the investments the providers of that energy will have to make in order to comply with a cap, a cost they will have to pass along to their customers. It struck me that the economic analysis assumes that small businesses are likely to respond to the higher energy prices by investing in energy efficient technologies to achieve those energy savings. This seems to be an unrealistic assumption considering that most small businesses and households are already doing everything possible to save on energy costs and don't have the resources to invest in new vehicles or other purchases that might save them a few dollars a month over a long period of time. As I said earlier, I wear two hats: the U.S. Hispanic Chamber and the business nonprofit of TELACU. In both situations I represent a segment of the community that suffers from disproportionately high unemployment and faces unique economic challenges. With the state budget deficit growing by the hour, there is more pressure for higher taxes, while at the same time there are fewer and fewer resources available in the social safety net, which is increasingly strained. This is not the time to impose drastically higher energy costs based on an over-optimistic assumption that it will all work out over time. (TELACU)

Comment: CARB has always maintained that in order to be effective, the cap and trade program must be part of a regional multi-state effort. Yet the regulation before you does not propose linking to any specific programs outside California at this time. If widespread equitable linkage cannot be accomplished, serious consideration should be given to postponing a cap and trade regulation. The LAO earlier this year observed that California's economy will be adversely affected by adopting climate change policies that are not adopted elsewhere, largely because of higher energy prices which will occur here. The LAO warned of rising costs for goods and service due to leakage of economic activity to locations outside of California where regulatory costs are lower. Your staff's economic analysis suggests that small businesses are not likely to face competitive issues with out-of-state businesses since out-of-state businesses cannot provide local services like those provided by hair salons and bakeries. This is incredibly shortsighted and reveals a lack of understanding of basic economics. While it is true that out-of-state taco shops, for example, are unlikely to compete with neighborhood taco shops, those local taco shops will suffer from increased energy costs that will be difficult to pass along to their customers. And they will lose customers whose own businesses have been competitively damaged by California-only cap and trade program. That means not only the owners of those small businesses, which make up the majority of our membership, will suffer. It also means that they are likely to have to lay off workers, who in turn will lost the wages and benefits upon which their families depend. While the proposed regulation and supporting documentation are voluminous, it appears there is yet much work to be done to identify the true costs of the program and its impact on small and minority-owned businesses, consumers, and the state's economy. The California Hispanic Chambers of Commerce urges you to address these issues before finalizing a cap and trade policy. (CAHISPCHMBR)

Comment: We're very concerned about the cap and trade and its impact on small business. And the assumption that it will have little impact on small business is just not the case. As energy costs increase, our small businesses are going to get hit in two areas: One is the direct cost to them for those energy increases in their businesses. And secondly is the cost of goods and services that they have to purchase in order to do business. And these small businesses are operating on such small margins, barely in the black right now. And any increases in cost can quickly send them into the red. And so it's really critical that we consider this. A lot of attention has been given to the costs of cap and trade. But the offsetting savings are vague and don't seem to be commensurate with the increased costs. (SACHISPCHMBR)

Comment: Very little has been done in the way of analyzing the real world impact to the end-users and those entities' products and services. This is of critical interest to small and minority-owned businesses and communities of color since they spend a higher percentage of their budgets on energy and can least afford even small increases in the cost of utilities and fuels. They will be hard hit when the cost of food, transportation, clothing, and other necessities goes up as can and trade costs are passed along to them as the end-users. While there is a discussion to provide assistance to small businesses and families who can't afford the utility rate increases, it's unclear how that would work and who would be eligible, how much help would be available, et cetera. And there is a strong possibility that ratepayer assistance won't begin to cover the other costs of everyday living and doing business outside of electricity and gas bills. Our small businesses are worried that in order to pay the bills under cap and trade, they'll have to lay off workers. Families are worried about losing paychecks and health care benefits at the same time the cost of living will be going up under cap and trade. Small businesses and families alike are worried about the cost of higher education, as some state universities subject to the cap were forced to raise tuition even higher and to cover those costs. (LOMBARD)

Comment: I'm representing the Coalition of Energy Users. We are thousands of taxpayers and small businesses who are concerned about this. I talk to small business owners every day that are concerned that these regulations could put businesses out of work, people out of work.
(COEU2)

Comment: Please do not attempt to enact or enforce this. Stacking this onerous load on the top of the already burdensome AB 32 will ring in the death knell for all too many of California's already struggling small businesses. (MGD)

> **Response:** Most small businesses will not be directly regulated under the California cap-and-trade program. The program will affect most small businesses only indirectly, through increases in energy costs. Under a contract

with ARB, Dun and Bradstreet provided us with data from a statistical data model that estimates the portion of revenue that businesses spend on energy. The vast majority of small businesses in California are not energy-intensive; that is, energy-related costs represent only a small fraction of their total revenue. So, increases in the price of energy will have only a modest financial impact. Under the likely range of allowances prices, most small business sectors experience less than a 2 percent change in the share of revenue spent on electricity and natural gas.

Higher energy prices may affect the price of intermediate goods and services that small businesses use; however, the increase in these costs is likely to be modest. We believe that the likely effects of the cap-and-trade program will be minor for small businesses and will be absorbed into the existing range of cost variation that they already face.

Please also see Chapter VIII and Appendix N of the Staff Report for additional information about our analysis of the impacts of the cap-and-trade regulation on small business.

Effects on Agriculture

H-3. (multiple comments)
Comment: The cap and trade rules being considered are not a practical solution to emissions. These rules would just add to the burdens on California's small businesses, in particular farmers who are the backbone of local economies. (CREW)

Comment: It is difficult enough these days for farmers to keep on producing crops because of all the costs and regulations. Do not pass this legislation. (MELL)

Comment: California farmers do not need, nor does the State of California need a Cap and Trade program. Please stop this attempt to further bankrupt our state. (RAADIK)

Comment: Farming is our number one income producer and you will effectively shut them down. Vote no on cap and trade. (GARDNER)

Comment: This proposed legislation will severely hurt our central valley farmers and economy in general. Please vote against this legislation. No to cap and trade. (PALOCSAY)

Comment: Please do not make it harder and more expensive on our food producers by passing more regulations. (WRIGHT)

Comment: Increased gas prices and increased costs to farmers and other productive parts of our economy are unconscionable at this time with the economy still extremely unsteady. Hang back and leave cap and trade greenhouse gas emissions to another decade, if ever. (SCHULTE)

Comment: As a Californian, I am adamantly against cap and trade. It will put small farmers out of business and raise gas prices and unemployment. (POWELL)

Comment: Even without this cap and trade adoption, we have a 12 percent unemployment rate. The cost of food, gas, and utilities are all continuing to increase, while the value of our dollar is shrinking. The intent to adopt the cap and trade proposal in this economic time is beyond ludicrous. I vote no. (MCADAMS)

Comment: We are cold all winter as we cannot afford propane and electricity as it is. A cap and trade bill will doom us. Please think how it will affect heating homes, farms, employment, etc. (CAMPO)

Comment: I am against crippling our State with Cap and Trade and higher taxes for farmers, on gas, etc. (IMPROTA)

Comment: I do not support CARB's energy tax proposal. This ill-conceived scheme will increase gas prices, cost jobs, shut down family farms, and make food more expensive. AB 32 is not about the environment it is about redistribution of wealth. In other words, it is meant to drive businesses, jobs and people out of California. If AB 32 is not suspended, you will see more and more businesses leave California and unemployment get worse. (BALL)

Comment: We do not support CARB's plans to raise gas prices, kill jobs and put the family farmer out of business. California cannot afford to pay higher prices for food and other things in our lives. If this continues you will drive business out of California. So please do not do this to our great State. (BOGGS)

Comment: Please review the state of business and farming in California before you implement draconian environmental regulations. The very idea that Man's activities today will cause the climate to change irreversibly in 100 years or so, is ridiculous on its face. The climate will continue to change whether AB 32 is implemented or not. California changing standards will affect the lives of the people living in California today. The immediate and known effects will be to further damage our failing economy. It is completely irresponsible to implement legislation which guarantees current injury with no reliable expectation of any future benefit. (STONE)

Comment: California is in the worst economic condition in decades. Family farms are on the verge of collapse. Unemployment is at record levels. Prices are rapidly increasing. People, companies, and jobs are streaming out of the State, to other, more business-friendly areas. Now is not the time to heap more regulations, more costs, and more taxes on the people of California. Please do not impose all these new regulations on us. (MCCARTHYJ)

Comment: CARB claims to want to boost consumption of locally grown food, but this will have the opposite effect by putting farmers out of business. Cap and trade is in collapse elsewhere, so why should we hurt our economy even more when other states and Washington all recognize how harmful this will be? (DURKEE)

Comment: Farmers will be hurt, the consumer will be picking up the tab. Jobs will be lost. (HENDRICKS)

Comment: It would be highly difficult for our family and many others to pay more for gasoline. It has cost the dairy farmers and other farmers' untold grief already. (DANIELE)

Comment: I cannot believe that in this poor economy, and with businesses leaving this State every day, you would dare to put through this terrible bill. We farm 22 acres and have a company that employs 90 people. I guess we will have to move out of this State so we can make a little profit to stay aboveboard and not have to lay people off. (BROOKS)

> **Response:** We recognize the importance of agriculture to the California economy and recognize that the agricultural sector is a large consumer of energy. Table 27 of the Updated Economic Evaluation of California's Climate Change Scoping Plan demonstrates that the impacts to agriculture from the AB 32 climate policies are relatively small and are roughly comparable to the impacts to other sectors of the economy.[3]
>
> Like other energy users, agriculture will face changes in electricity, natural gas and transportation fuel prices. ARB analyzed how significant the contribution of energy prices was to food processors and found that compared to other agencies, the contribution was low. Please see Appendix K of the Initial Statement of Reasons for additional information about our leakage analysis. ARB believes that these small additional costs can be passed through to consumers.

Need to Postpone Because of the Economy

H-4. (multiple comments)

Comment: It's an effort to show leadership, but I'm concerned that other states have not wanted to participate in this program. Right now we have only New Mexico. Congress as a whole now is a majority that is opposed to cap and trade. Please look at the hundreds of online comments from regular citizens and business owners who are urging you to postpone this plan. I know some have posted that with Proposition 23, it's a mandate to go full speed ahead. However, please also realize that three million Californians voted yes on 23 and believe that there are very serious concerns that should be addressed. This is not something we can afford right now with record high unemployment, a $20 billion budget deficit, and at a time when the nation as a whole does not wish to go forward with this plan. I hope you will at least consider postponement for economic reasons. (COEU2)

[3] http://www.arb.ca.gov/cc/scopingplan/economics-sp/updated-analysis/updated_sp_analysis.pdf

Comment: Implementing Cap and Trade during a recession in a state (California) with very high unemployment and one foot in bankruptcy is insane. (HOYT)

Comment: Although California, due to its topography and population, is challenged by greenhouse gases, it is definitely not time to enact this legislature with the state of the economy in California and the U.S. Please put this on hold until California is well on its way to economic recovery. Enactment of this legislature will only hurt California more in the long run than help. (HEYN)

Comment: California proceeds alone at its economic peril. California will begin its cap and trade system without the commensurate participation it had hoped to stimulate from neighboring political subdivisions and the federal government, which in turn will have major consequences likely resulting in a range of negative economic impacts on California businesses. (PLOTKIN)

Comment: No more regulations. We are the most environmentally regulated country (and state) on earth. The cap and trade legislation is little about the environment and more about control. Our economy has the potential to affect the entire nation. California is so vulnerable. This legislation will no doubt encourage inflation as the commodities we depend on most increase in price. The legislation will destroy jobs, businesses, lives, and families. (PHILLIPSE)

Comment: The economy is still in the tank and you want to impose additional costs that will hurt the economy. I believe we should move forward continuing to help clean up the environment but we should start approaching it during a financially promising time; not now. This will not do a thing to help us rebound from this economic crisis. (AYERS)

Comment: Doing this at this time would be bad for business. The economy is just starting to turn around. Why risk scaring away potential businesses that might want to come to California? Why make it more difficult for current businesses to grow? Stop this. Wait until unemployment is below 5 percent and then work on emissions. (BRAXTON)

Comment: Stop adding additional burdens. Give the economy time to recover. (LYNES)

Comment: Implementation of any sort of cap and trade regulation in California promises to increase our already-nation's-worst unemployment, raise our already-high gasoline and electric utility costs, and increase the rate at which businesses choose to leave (or simply not come to) our fair State. While the issue of global climate change is important and should be given due attention, we in California simply cannot afford a Quixotic attempt to halt carbon emissions at our borders. I suppose CARB has the administrative power to make this regulation happen. The sad fact is that if you choose to do so, you will find yourself exercising more and more control over fewer and fewer people, with a smaller and smaller budget due to ever-declining tax revenues. (MCGLASSON)

Comment: Ask yourself before voting yes on this legislation is this really the time and place to over burden the people of this once great State with such a damaging piece of work. This will hurt all families who purchase anything, it will drive cost up of nearly everything we need to survive we do not need this now or later. (PACKER)

Comment: I respectfully request that you slow the pace of implementing this new legislation. Our State cannot afford to continue letting special interest radical groups to develop and push legislation that continues to place us at a disadvantage to the rest of the nation and world. This Cap and Trade legislation will do nothing more than hurt employment in the State while lining the pockets of a few investors. And it will make no change in the rate of "global warming." The law of unforeseen consequences continues to be proven time and time again by legislation such as this. I urge you to carefully read all of the proposed regulations and then present them to the public for comment. (MORTIMER)

Comment: This proposal is utter madness in the current economic climate. The State can NOT afford this right now (if ever). Cap and Trade simply will not work and will cause much harm to the entities that have the ability to do something about the environment in the future. (JEMISON)

Comment: In California's current fiscal and economic environment, we need to maintain a focus on implementing a program that will not undermine the state's nascent economic recovery. (CHEVRON1)

Comment: While everybody cares about the environment, please postpone your cap and trade plan and take into account the costs this will impose on our already weak economy, the failure of cap and trade to gain traction elsewhere and the deep opposition of millions of California taxpayers and business owners. Even your own analysis estimates the cap and trade proposal will result in a loss of GDP, and many other researchers have estimated much greater costs. The cap and trade proposal discusses business owners having the choice of paying cap and trade taxes or alternatively investing in new equipment. The writers of the proposal may think this is a generous proposition by giving the carbon-emitter the choice of what type of additional costs they would like to incur, but the fact is many small businesses are already operating in the red and cannot afford either option. Regular citizens are currently struggling and cannot afford these additional costs. (COEU1)

Comment: This and other pseudo-environmental regulations will only hinder our state's economic recovery, and will impose even more draconian measures on our families, farms and businesses. This is hardly the time to discourage jobs and employment prospects. The notion of a "green" economy is based on assumptions that do not stand up to objective analysis. (PHTA)

Comment: In this time of high unemployment and poor job creation, you want to implement this costly program? You will drive the prices of everything up in a down-turned economy. As a business owner, I can undoubtedly say that I will raise prices to accommodate the increased costs. The rules and regulations in this state are driving businesses and private job creators away. (HERR)

Comment: Why now at a time of high unemployment, a not too rapidly recovering economy, would we risk killing jobs? If indeed we're not trying to redistribute the wealth from those of us that have it, whether it's through attention to their medical needs or attention to their energy needs through the state. That makes no sense to me. (FORD)

Comment: It doesn't take a genius to realize this is not the time to be placing additional strain on businesses in CA. The PM2.5 diesel regulations have forced many truckers out of business already. How many deaths do you think will be a direct result of 25-50,000 families losing the breadwinner of the household? In case you weren't aware. Poverty kills. (MILLERJEF)

Comment: In any circumstances I would not support this proposed cap on greenhouse emissions because of its impact on agriculture. Every Californian will be affected by this new regulation because of its impact on the farming community. The people that pass this will be responsible for every California farmer who goes out of business and loses his home and farm. Compassion and common sense can prevail and this part of AB 32 can be put on hold for at least another year if not two. (PALM)

> **Response:** The cap-and-trade regulation is designed to be a cost-effective means of achieving the statutory requirement in AB 32 of reducing 2020 greenhouse gas emissions to 1990 levels. ARB found that cap-and-trade is likely to be the most cost-effective means of achieving these reductions. See Chapter IV of the Staff Report for additional information about alternatives to the cap-and-trade regulation that we considered.
>
> In addition, we designed the program to gradually phase in the auction of allowances and with cost containment mechanisms such as banking, offsets, and an allowance price containment reserve to protect against high prices and price volatility.
>
> It should also be noted that a policy such as cap-and-trade provides relief in slow economic times because the emission cap is largely met from the reduced production and consumption that accompany the economic downturn. As the economy recovers and incomes increase, produces and consumers will have the means to make the necessary investments to help them make permanent emissions reductions.
>
> We are also providing an additional year for covered entities to better prepare and plan for when ARB will enforce the cap by designing the program to have a compliance obligation in 2013 instead of 2012.

Market Price of Allowances

H-5. (multiple comments)
Comment: Expectations about the Federal market after 2020 have significant influence on banking behavior and thus on the equilibrium allowance price in the California market during the period 2012-2020. If unlimited banking is allowed, and a Federal program comes on line after 2020, the allowance price in the AB 32 market will be determined in part by the expected federal price. The strength of this effect depends on the stringency of the AB 32 cap relative to the BAU baseline (taking into account offsets and complementary measures). The less abatement is required by AB 32, the more the California price will be driven by the expected federal price. The importance of the federal price also means that assumptions about the design of a federal cap-and-trade system—for example, the trigger price for a federal allowance reserve—are key drivers of predicted outcomes in the AB 32 market. (EDF1)

Comment: The effectiveness of complementary policies also plays a central role in the market price of allowances and in the performance of the reserve. The base-case assumptions provided by CARB include an estimate of reductions from complementary policies, such as energy efficiency measures, the renewable electricity standard, and the low-carbon fuel standard. These complementary policies (along with the projected supply of offsets) will likely be more than sufficient to achieve the reductions required by AB 32. In this case, if the program is modeled without banking after 2020 (i.e., we consider the AB 32 market from 2012-2020 as "self-contained"), the allowance price is likely to be set by the marginal cost of offsets. If post-2020 banking is allowed, the only economic reason for abatement (beyond offsets and complementary policies) prior to 2020 is to bank in anticipation of post-2020 price. In this case, the price distribution will be dominated by expectations of the future federal allowance price. (EDF1)

> **Response**: We agree with these comments. In a post-2020 market, the allowance price will be influenced by what happens in both California and at the Federal level. However, what a post-2020 market will look like is still very much an unknown.

H-6. Comment: For the system to succeed, carbon must be priced high and priced ever higher during the years following. (BEAZLIE)

> **Response:** By design, as the number of available permits decline, the price of allowance will increase, providing for higher allowance prices in the future.

General Opposition to the Program

H-7. (multiple comments)
Comment: How is this extra tax going to be justified? (STEELER)

Comment: Just where is this ill-gotten gain going to go? Who made this agency and this ideology so important that they can control the citizens of this state through these unfair and unnecessary penalties? (STEELER)

> **Response**: The California Global Warming Solutions Act of 2006 (AB 32, Nuñez, Chapter 488, Statutes of 2006) mandates that GHG emissions be reduced to 1990 levels by 2020. In addition, AB 32 assigns ARB the authority and responsibility to implement measures that reduce greenhouse gas emissions. The cap-and-trade program is one of those measures chosen to meet the reduction requirements.

Fiscal Impact Statement-Form 399

H-8. Comment: The fiscal impact statement associated with the regulation incorrectly assumes that Reid Gardner electricity will be imported only until December 31, 2013. However, the termination date is July 25, 2013, six days short of 19 months. The fiscal impact statement should be revised accordingly. (DWR)

> **Response:** The Form 399 has been changed to reflect the correct termination date of the contract with Reid Gardner.

H-9. Comment: The fiscal impact does not account for delays in billing and collecting charges built in to the long-term SWP water supply contracts and resulting mismatch in costs of purchasing allowances and incurring surrender obligations which could have a fiscal impact to DWR. (DWR)

> **Response**: Most regulated entitles will face the same issue and will have to adjust billing schedules or find other sources of revenue that will allow them to secure allowances.

AB 32 Not Specific to Cap-and-Trade

H-10. (multiple comments)
Comment: I oppose the implementation of AB 32. This will hurt CA business and will force more unemployment in CA. (FARLY)

Comment: I am against AB 32 and what it will do to the cost of living. All services and goods in California will become much more expensive. Electricity, gas, diesel, natural gas, groceries will shoot through the roof. (GIANNINI)

Comment: California needs to be more citizen- friendly. AB 32 will cause the economy to get worse. California needs jobs, jobs and more jobs. No new taxes, no more added regulations and work with private businesses to get things moving again. (RAY)

Comment: AB 32 is a job killer, no way around it. It will raise prices, drive jobs out and the green jobs won't begin to replace the lost ones. Quit killing CA, we are already bankrupt. (MYERSH)

Comment: I am opposed to the implementation of regulations associated with AB 32. To continue to tax the salaries of those few who can still find a job in this Once Golden but Not Anymore State is to kill the golden goose. Honey, the electorate are your golden geese and we are DYING. Enough taxation. (KINNARE)

Comment: California is experiencing its worse economic downturn since the 1930s; and part of the problem is due to government actions that kill economic activity. Companies will vote with their feet and move to other more business friendly states and will take their economic generating businesses with them. AB 32 is a recipe for economic disaster. (MANGAI)

Comment: Small refiners are clearly being disproportionally and negatively impacted economically by the AB 32 regulations and should be recognized as a distinctive subset of the California refining industry. (KERNOIL1)

Comment: I urge this committee not to implement this provision of AB 32. Californian's are being taxed to death. The economy in California is on the verge of bankruptcy and if you implement any portion of AB 32 this state may not survive. Please don't strap the people of this great state with more taxes. (YOUNGHARLAN)

> **Response:** The California Global Warming Solutions Act of 2006 (AB 32, Nuñez, Chapter 488, Statutes of 2006) mandates that GHG emissions be reduced to 1990 levels by 2020. In addition, AB 32 assigns ARB the authority and responsibility to implement measures that reduce greenhouse gas emissions.
>
> In 2010, we conducted a joint economic analysis of the AB 32 Climate Change Scoping Plan with Charles River Associates and Professor David Roland-Holst of the University of California Berkeley. The estimated price of CO_2 in these three analyses ranged from about \$20/MTCO_2e to \$100/MTCO_2e in 2020. The range of prices in those analyses depended on assumptions about the success of other AB 32 policies and whether offsets were allowed for compliance. Changes to the state economy and employment were found to range from small positive changes to small negative changes, indicating that AB 32 policies will not result in large negative impacts to the state economy.[4]
>
> Economic analysis performed for the cap-and-trade regulation showed that the regulation would not have large negative impacts to the state economy. Table N-3 and Table N-7 of the staff report highlight estimated changes in energy prices and resulting economy wide estimates of impact. The estimated impacts show relatively small changes in economic growth and employment when

[4] http://www.arb.ca.gov/cc/scopingplan/economics-sp/meetings/042110/outline.pdf

compared to growth otherwise expected over 2007 to 2020. Please see Chapter VIII and Appendix N of the Staff Report for additional information about our economic analysis of the cap-and-trade regulation.

The cap-and-trade program does not specify how or where emissions reductions will be made. Reductions will be made by covered sources if the cost of making reductions is less than the cost of acquiring allowances, thereby minimizing price increases. Further, free allocation to some covered entities at the beginning of the program will assist with transition and reduce the potential for economic leakage. The regulation is also designed with cost-containment mechanisms such as banking, limited of use of offsets, and an allowance price containment reserve.

For non-covered sectors of the economy, individual households and businesses are not expected to make rapid or extreme changes in their purchase decisions of energy consuming devices (e.g., appliances or automobiles). Devices have useful lifetimes and have to be replaced at some point. The responses to the cap-and-trade program will be to slightly shorten the useful lifetime of the devices. Therefore, individuals may replace the devices sooner and may choose devices with higher efficiencies than they would have otherwise chosen.

Our economic analysis evaluated the impacts of the regulation on both small businesses and individual consumers. Based on analysis of data from Dun and Bradstreet, we found that the small business sectors with the greatest percentage of their revenues spent on electricity and natural gas were primarily service-related and serve local markets. Out-of-state businesses cannot serve these markets. As a result, most California small businesses are not likely to face competitiveness issues relative to out-of-state businesses. Under the likely range of allowances prices, most small business sectors experience less than a 2 percent change in the share of revenue spent on energy.

There are existing programs that will help households and business identify energy-saving opportunities and provide assistance in making efficiency improvements. Finally, auction revenue could be used to reduce or eliminate negative impacts to most individual households.[5]

H-11. Comment: DWR is concerned that in the early years of cap and trade, when its surrender obligation will come due, there will be too few allowances available. It is not clear that by the time DWR must surrender its compliance instruments there will have been adequate opportunity to purchase allowances at a reasonable price. Without a price cap on the allowances, large price spikes are possible. DWR would be competing against independent power producers, who will be able to pass the cost of allowances on to their customers (one of whom is DWR). Against the background of public budgeting and revenue collection, which are conducted in pre-established time periods,

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[5] http://www.climatechange.ca.gov/eaac/documents/eaac_reports/2010-03-22_EAAC_Allocation_Report_Final.pdf

DWR may face fiscal difficulties and cash flow problems in making purchases of high-value allowances. DWR requests that the ARB consider excluding DWR from the regulation to avoid these adverse impacts, or structuring the auctions in a way that this threat is reduced (perhaps with a set-aside of allowances for public agency use or a price cap). (DWR)

> **Response**: We believe that between allowances made available at auctions, allowance price containment reserve sales, the secondary market, and the option to use offset credits, covered entities will be able to obtain a sufficient number of compliance instruments to meet their obligations.

H-12. (multiple comments)
Comment: AB 32 requires regulations to be cost effective and to minimize costs and maximize total benefits to California (section 38562). In addition, the mandated reduction must be in addition to any other greenhouse gas emission reduction that otherwise would occur (section 38562). DWR's surrender obligation and associated costs will be attributable only to the emissions related to the importation of energy from the Reid Gardner power plant for the period January 2012 through July 2013. This contract is already scheduled for termination, effective July 2013. Imposition of surrender obligations on DWR due to Reid Gardner will not induce the contract's termination; that has already been decided. Procurement of alternative energy to replace Reid Gardner will need to meet the performance standard mandated by Water Code section 142. The only consequence of naming DWR as a "covered entity" under the proposed regulation is to impose on DWR the cost of allowances necessary to surrender the compliance obligation. The reduction in GHG is one that would "otherwise occur" and accordingly cannot be considered an appropriate reduction under AB 32's section 38562. In addition, it cannot be considered cost-effective. "Cost-effectiveness" means "the cost per unit of reduced emissions of GHG adjusted for its global warming potential" (section 38505(d)). The regulation does not reduce these emissions because they are already planned for reduction independent of the regulation. The regulation merely imposes a cost without reducing GHG, and accordingly is not cost-effective. It would be more cost effective to allow DWR to use its resources to fund other GHG reduction or mitigation strategies. (DWR)

Comment: The regulation is not cost-effective because the expenditure of money on allowances will do nothing to further AB 32 goals. As noted above, the linkage between DWR's purchase of allowances and individual consumers' water use is very attenuated; there is no connection with retail electricity use. There should be a more direct link to justify the expense of purchasing allowances. (DWR)

> **Response**: There are important policy reasons to include DWR in the cap. The cap-and-trade program is designed to both place an enforceable and declining cap on greenhouse gas emissions, and to send a price signal to encourage more efficient use of energy. As part of this program, it is important to create a level playing field in order to send a consistent price signal. If ARB were to remove

DWR from the cap, it would inappropriately incentivize electricity imported by DWR since they would not be subject to the price signal.

First deliverers of electricity, like DWR, are not eligible for free allocation of emissions allowances because we believe that the cost of allowances can be passed on to the consumers of the electricity. Free allocation of emissions allowances is only for sectors at risk for emission leakage. Most regulated entitles will face the same problem and will have to adjust billing schedules or find other sources of revenue that will allow them to secure allowances at the beginning of the program.

H-13. (multiple comments)
Comment: Local governments that are already severely impacted financially by the economic downturn cannot afford to absorb the cost of emissions allowances or their administrative costs. Under the current CARB proposed program, waste-to-energy facilities will not enjoy the benefits of free allocations that are being offered to electric, gas and oil utilities, as well as other industries. CREF, like other waste-to-energy facilities that operate in California, receive post-recycled waste, and have no control over the incoming waste stream or practicable means to reduce the fossil-based components of the MSW (largely plastics). Thus, no options are available to meet the facilities compliance obligations except via purchasing allowances. As the price of allowances inevitably increases, in time this amount could easily exceed a million dollars per year. CREF, like other waste-to-energy facilities, has no ability to pass this allowance cost through, contrary to a critical but incorrect assumption that CARB has made about these facilities. Two main reasons exist that prevent passing costs through to haulers. First, CREF has fixed-rate electrical contracts that do not allow for any cost recovery of allowances. Second, if CREF raises its tipping fees, haulers using the facility would simply take the waste to local, cheaper landfills, resulting in an increase in greenhouse gas emissions due to increase methane emissions at the landfill. The overall impact to the City of Commerce, as well as its operating partner, the Sanitation Districts, would be the need to absorb the allowance cost, a cost which would recur each compliance period at an ever-increasing dollar amount, every year into the foreseeable future. (LASD1)

Comment: CREF, like other waste-to-energy facilities, has no ability to pass this allowance cost through, contrary to the critical but incorrect assumption that CARB has made about these facilities and the economic impacts of the cap-and-trade regulation. Two main reasons exist that prevent passing costs through to haulers. First, CREF has fixed-rate electrical contracts that do not allow for any cost recovery of allowances. Second, if CREF raises its tipping fees, haulers using the facility would simply take the waste to local, cheaper landfills, resulting in an increase in greenhouse gas emissions due to increase methane emissions at the landfill. The overall impact to the City of Commerce, as well as its operating partner, the Sanitation Districts, would be the need to absorb the allowance cost, a cost which would recur each compliance period at an ever-increasing amount, every year into the foreseeable future. Local governments that are already severely impacted financially by the economic downturn cannot afford to absorb the cost of emissions allowances. Not doing so will have a severe financial impact on the facilities and the local governments that own them and that they serve. (CREA)

Comment: The Sanitation Districts waste management facilities emit largely biogenic CO_2 because of the combustion of biogases (landfill and digester gas). One of our facilities however, the Commerce Refuse-to-Energy Facility (CREF), also emits anthropogenic CO_2 due to the combustion of fossil-derived consumer end products in the waste stream, consisting largely of plastics. CREF is one of three waste-to-energy facilities in California, all built in the 1980's with the support of the California legislature that established laws to encourage these renewable energy facilities. Even though the biogenic fraction makes up the majority of the emissions (approximately 60 percent), the anthropogenic CO_2 emissions are sufficiently large to trigger the cap and trade threshold. For the reasons that follow in greater detail, we request that these facilities be removed from the proposed program because of the severe financial burden that would be placed on them, and on the local governments under which they operate. (LASD1)

> **Response**: There are important policy reasons to include waste-to-energy facilities in the cap. The cap-and-trade regulation is designed to both place an enforceable and declining cap on greenhouse gas emissions, and to send a price signal to encourage more efficient use of energy. As part of this program, it is important to create a level playing field in order to send a consistent price signal. If ARB were to remove waste-to-energy facilities from the cap, it would inappropriately incentivize electricity generated by these facilities, since they would not be subject to the price signal.
>
> Generators of electricity are not eligible for free allocation of emissions allowances because we believe that the cost of allowances can be passed on to the consumers of the electricity. Free allocation of emissions allowances is only for sectors at risk for emission leakage. We do not believe, and data has not been provided that shows that the three waste-to-energy facilities are at risk for emissions leakage.

H-14. (multiple comments)
Comment: The proposed regulation will have a significant impact upon the university. We have five cogeneration plants and one large heat thermal plant that will be captured by the cap and trade regulations. We estimate that the cost of purchasing allowances on the auction will range between 7 million and 30 million per year, depending upon the actual cost of the allowances on the auction. The university and higher education and education in general is under significant financial pressure. The amount of state funding of the university has declined dramatically since 1990, by 51 percent of the cost of funding of each student. We've had to increase tuition and fees by roughly 40 percent over the last two years. And the cost to comply with the program by purchasing allowances would of course come out of general funds and would have to either come

out of tuition and fees or state funding, which is unlikely given the dire strait of budget situation. So we ask for transition assistance. (UC2)

Comment: The University supports the creation of a greenhouse gas Cap and Trade program, but is concerned that it is being disproportionately impacted by the proposed Cap and Trade rule and that its compliance costs will ultimately be borne by students, researchers, and patients to the detriment of teaching, research, and healthcare activities. In light of these concerns, the University submits comments to facilitate creation of a Cap and Trade program that treats public higher education in a manner that is consistent with the treatment of other entities that are regulated under the proposed Cap and Trade rule. (UC1)

> **Response**: Free allocation of emissions allowances is only for sectors at risk for emission leakage. We do not believe that the University of California is at risk for emission leakage. Our analysis shows that even if all compliance costs were passed on to the students, the increase in student fees would be minimal because of the compliance obligation. It should be noted that the University of California also has additional options to reduce their compliance costs (by making their facilities more efficient) and for passing through the compliance cost (to research or other university activities).

Fuels Under Cap: Compliance Obligation

H-15. (multiple comments)
Comment: The idea of full and automatic pass through of allowance costs to consumers is not valid: Under the proposed regulation, there is no certainty that these costs will be passed through to the final consumer. Any costs that are not passed through will provide a particular disadvantage to the small, less integrated refiner. Kern suggests that staff be directed to establish a mechanism to assure that these costs be fully passed through as a separate and distinct invoice line item. This mechanism shall be in the form of a linked allowance utilizing a uniform rate per gallon based on tailpipe carbon emissions, and known in advance. (KERNOIL1)

Comment: Assumed cost pass through for allowance costs of transportation fuels is incorrect. The Regulation and staff report assert that the costs associated with allowance value of transportation fuels will be passed along to the consumer, and thereby relieving the obligated party from bearing the burden of those costs. This assertion is incorrect for the independent, non-vertically integrated refiners. Costs will be passed through with a degree of certainty only if a mandated mechanism is in place specifically for this purpose. For consumers to see the additional carbon cost of the program and to adjust their behavior accordingly, a mechanism needs to be in place for those costs to be passed along directly. Relying on general market forces to adjust for the price of carbon is not sufficient when the marketplace includes such diverse players as importers, small refiners, large integrated exploration, refining and retail operations, speculators and others who have the ability to establish product price independent of actual production costs. We recommend allowing for the cost of allowances to be specifically invoiced nearer the final point of sale. (WIRA1, PMTPETRO1)

Comment: Placing fuels under the cap represents a significant cost to the state on top of many other regulatory schemes that are already adopted. The cost impacts to consumers in California as we emerge from a recession cannot be underestimated. At a minimum, placing fuels under the cap must be avoided at least until there are widespread cap and trade programs that include fuels across the US and around the world. None of the cap and trade programs throughout the world include fuels in the cap and trade programs, except New Zealand. If we do not fully review the economic impacts prior to adopting this policy, we risk unfairly punishing our residents and our state's economy unfairly. Chevron recommends that fuels not be placed under the cap until additional study of the impacts and alternatives are completed and should not be considered until there are widespread cap and trade programs that include fuels across the US and around the world. (CHEVRON1)

Comment: Placing diesel fuel under a declining cap as part of the Cap and Trade Program in 2015 will cause warehousing in California irreparable harm. Leakage of cargo and the associated value added services that California warehouse and supply chain partners provide to other ports, specifically Seattle, Houston, Panama and Canada do not improve overall carbon emissions.

Continuing on the current path and placing diesel fuel under a declining cap in California will do the following to the businesses left in a state:

1. Create volatile carbon prices that are recognized only in the California supply chain and require 3PLs to redesign shipping lanes and warehouse locations. California will be left with the trucks and the pollution from other states but none of jobs.
2. Repeat the State fuel crisis of 1993 and 1996, defined by a price shock in the beginning of the second compliance period negatively impacting overall allowance prices for the entire program.
3. Decrease actual volumes of low carbon fuel sold and burned in the State while increasing the sales of diesel fuel from other states created by the redesign of shipping lanes. The leakage in interstate fuel burned in the State will increase the criteria pollutants that have actual health impacts rather than symbolic carbon reductions from California.
4. Become a marketing campaign for the 2014 Panama Canal Opening creating speculative movement of freight out of California before the 2015 introduction.
5. Make diesel transportation users the highest cost sector for compliance under the scoping plan while ignoring the low cost method of engine efficiency standards. Fuel reformulation is not cost effective either through the low carbon fuel standard or the placement of fuels under the cap. Adopting them both in the same year is punitive to the transportation sector.
6. Drive up the allowance price for utilities and refineries leading to increased fuel prices and electricity prices. Commercial electricity users left behind in allocation of residential free allowances will shoulder increased rates caused by renewable energy mandates for utilities. Every commercial business in the State, including local warehousing, will be faced with increased electricity costs. (IWLA1, IWLA2)

Comment: The proposed California only "Cap and Trade" regulation creates significant cost increases in diesel fuel for companies that are forced to fuel in California. CTA is opposed to placing diesel fuel under the cap for the following reasons and requests that CARB remove diesel fuel from the Cap and Trade Program in the interest of California jobs and a level playing field. The following issues can only be addressed by taking diesel fuel outside the Cap and Trade Program's declining cap as it will:

1) Create a California-only 30 cent per gallon fuel tax based an allowances market price of $30 per metric ton CO_2 equivalent.
2) Double regulate the trucking industry with two punitive measures impacting fuel costs. First, the low carbon fuel standard and second, diesel fuel under the cap significantly impacting the price of in state diesel fuel.
3) Displace fuel purchases from interstate carriers to outside the state and increasing the use of out of state diesel fuels in California in violation of the State Implementation Plan.
4) Disadvantage California diesel users who compete with interstate carriers for California freight transferring freight accounts outside the state.

5) Creates a diesel fuel price signal needed to drive investment in cleaner fuels but that leaves California's trucking industry in peril and the state in a financial crisis.
6) Creates price shock in 2015 by adding fuels under the cap when allowances are scarce. (CTA)

Comment: The Cap and Trade program should not be extended to transportation consumer emissions as provisions of other federal and state programs address these. Additionally, fuel providers should not be responsible for these emissions that are directly consumer related. Transportation emissions should be considered only if a formal review determines that this action is necessary and implementation would be more cost-effective than other policy approaches. The proposed regulations include GHG emissions from consumer use of transportation fuels under the state emission cap starting in 2015 (section 95812(d)(l)). This results in a clear overlay to the existing federal Renewable Fuels Standard, the California Low Carbon Fuel Standard (LCFS), and state/federal vehicle GHG performance standards. Transportation GHG emissions are being substantially addressed through current federal and state programs (i.e. federal fuel economy programs, federal renewables programs and state LCFS programs). Cap and Trade is not well-suited to address emissions from millions of distributed point sources such as automobiles. Inclusion of transportation fuel emissions within the Cap and Trade program will add a volatile carbon cost to the price consumers already pay for GHG control measure such as LCFS and vehicle efficiency standards. In addition, fuels under the cap will increase administrative complexity and the market price of emission allowances for all the other capped sectors. Specifically, a carbon cost of $20 per ton would add a fuel cost burden in excess of $3 billion per year to the California economy. In addition to individual consumers, much of this cost will fall to businesses and municipalities impacting small business owners, truck drivers, city bus and trash services, construction companies, rail services, and others. This carbon cost, along with the cost of compliance for LCFS and federal programs, will be embedded into the costs of all goods and services that rely on transportation. CARB should not extend the Cap and Trade program to consumer emissions from use of transportation fuels. Instead, CARB should allow existing federal/state programs to address GHG emissions in this sector. This is consistent with the approach adopted in the European Union. Any inclusion of consumer use of transportation fuels under the state emission cap in 2015 should be contingent on a formal review and a conclusion that such a measure is necessary and cost-effective for achieving the State's GHG reduction goals. We seek the Board's resolution that would require staff to review inclusion of transportation consumer emissions in the cap. This review should be completed well before the proposed 2015 start date. (CONOCO)

> **Response:** As noted in the regulation’s Staff Report, we chose to include transportation fuels in the program starting in 2015 because together it is the largest source of GHG emission in California. We believe that cap-and-trade’s market-based approach is the most cost-effective and practical approach to lower emissions throughout most of California’s economy. There are numerous sectors that are covered by direct regulation and the cap-and-trade regulation.

For example, the electricity sector is subject to the Renewable Portfolio Standard as well as the cap-and-trade regulation. We believe that the cap-and-trade-program is complementary to existing renewable and LCFS standards and to other State or federal laws.

The LCFS regulates fuel producers by requiring them to reduce the carbon intensity of their fuels 10 percent by 2020. This is accomplished by creating various “fuel pathways” for fuels based on their lifecycle emissions, accounting for feedstocks, production processes, transporting fuels, and other factors. While the LCFS will incentivize the use of lower carbon, non-petroleum fuels, it does not address emissions from petroleum refineries. The cap-and-trade program addresses both facility emissions that occur from fuel production (beginning in the first compliance period) and accounts for combustion emissions from the fuel that is produced and sold in California (beginning in the second compliance period).

Placing a price signal on transportation fuels will reduce the consumption of transportation fuel; driving investment in newer, more fuel-efficient vehicles. Any GHG reductions resulting from federal regulations or the LCFS at covered entities would be counted as emission reductions under the cap-and-trade program.

We agree that cap-and-trade is not well-suited to address emissions from millions of distributed point sources such as automobiles. However, our approach is not to apply cap-and-trade to the end user (vehicle drivers), but to the fuel suppliers, who will be responsible for fuel that is combusted. By taking this “upstream” approach in the regulation, we avoid the challenges of applying it to millions of “downstream” users.

Compliance Pathways

H-16. (multiple comments)
Comment: CLFP recommends ARB recalculate pay-back periods to reflect actual industry practices. (CLFP1)

Comment: Assumptions on pay-back periods are faulty because CARB assumes pay-back periods on an annual basis. In Appendix F, staff proposes emissions reduction strategies asserting in the regulation that pay-back periods on capital costs are under three years. As food processors only operate a few months out of the year, this pay-back period on technology adaptation is unworkable for the food processing industry. Any pay-back for capital investments would be significantly lengthened due to seasonal operation norms. (CALFP1)

Comment: PG&E reviewed the offset price estimates presented in Appendix F and offers the following feedback. On page F-42, the price of forestry offset credits is estimated at $4 per metric ton. Based on experience through PG&E’s ClimateSmart™

program, forestry offset projects are currently being sold for between $7 and $10 per metric ton. Ozone-depleting substance and livestock methane capture projects go for between $5 and $7 per metric ton. This is consistent with an annual report on the voluntary market which shows an average price of forest management projects at $7.3 per metric ton and livestock methane capture projects at $5.7 per metric ton. (PGE1)

> **Response:** The compliance pathway analysis was designed to show different means for regulated entities to comply with the regulation. It relies on many assumptions, including technology costs and availability, payback period, offset availability and cost, and the rates at which technology can be applied to California facilities. We believe that the assumptions in the pathway's analysis are reasonable. Currently, we are not planning on updating the Compliance Pathways analysis, but we will take these comments into consideration should we update it in the future.

Offsets

H-17. Comment: If the Board adopts the cap and trade regulation, instead of direct emissions reductions, then the unbridled use of offsets from out-of-state will mean that the jobs and economic benefit resulting from those reductions will not benefit California. The Legislature surely did not intend that offsets from planting trees in Canada would be an appropriate market-based mechanism. (CRPE1)

> **Response:** In designing the cap-and-trade regulation, we had to balance many objectives. The use of offsets provides an important cost-containment mechanism, while also encouraging the deployment of greenhouse gas-reduction technologies in uncapped sectors. Table 26 of the Updated Economic Evaluation of California's Climate Change Scoping Plan demonstrates that the impacts to the state economy of a cap-and-trade program that does not allow for the use of offsets are substantially greater than in a program that allows for the use of offsets. It should also be noted that the cap-and-trade regulation limits the use of offsets to eight percent of each entity's compliance obligation in each compliance period.

H-18. Comment: ARB's forecast estimates provided in Table G-1 of Appendix G overlook two important items. First, the forecast assumes that offset volume is only dependent on price and second, that a sufficient volume of offsets will be developed if the price is high enough. This forecast does not consider the limits based on the current approved protocols and the "feedstocks" needed to develop GHG emission reductions. For example, at the ARB's June 22, 2010 workshop, ARB Staff estimated the volume of GHG emission reductions from ozone-depleting substances at 30 million metric tons between 2012 and 2014. This estimate was based on existing ODS banks calculated by the U.S. Environmental Protection Agency ("EPA"). When estimating supply, any analysis needs to consider that once these ODS are destroyed, there is no additional volume. For livestock manure capture projects, the number of projects is limited by the number of cows. It is estimated that there are 1.4 million dairy cows in California. The average cow generates about 5 metric tons of carbon dioxide equivalent per year. Therefore if the methane was captured from every dairy cow in California, you would only generate 7 million metric tons of GHG emissions per year. In order to meet the demand for the first compliance period, every dairy and every ozone-depletion substance bank would need to be in the process of developing their projects. Because offsets are limited by the feedstocks (refrigerants, cows, trees), it is not possible to meet the theoretical potential in this analysis even at high offset prices. (PGE1)

> **Response**: We estimate that if every entity used their allowable eight percent offsets, approximately 26 million metric tons of offsets would be needed in the first compliance period. At this time, based on the four approved protocols, we will be close to the supply demand for the first compliance period. In addition to the four approved protocols, we intend to review and recommend for Board approval additional offset protocols in the future. On August 24, 2011, we announced that ARB will investigate three additional protocols for possible consideration by the Board in 2012. These include pneumatic valves and two potential agricultural protocols. We expect that these protocols could provide 15 to 20 million metric tons of reductions. Protocols developed by third parties may be reviewed and, if applicable, be considered for adoption by ARB. In addition, we will coordinate closely with the WCI partner jurisdictions on offset protocol development.

Linkage

H-19. Comment: Until further details develop for both additional entities to develop a viable carbon market by 2012, and ARB delineates specific details regarding the linkage of these programs, we view the California Cap-and Trade regulation as a state-only program that will have significant economic impacts due to its limited markets and place California businesses in a competitive disadvantage. (VALERO)

> **Response**: ARB evaluated the potential economic impacts of the cap-and-trade regulation and found that the program would have a very small impact on economic growth. Table N-3 and Table N-7 of the staff report highlight estimated changes in energy prices and resulting economy-wide estimates of impact. The estimated impacts show relatively small changes in economic growth and employment when compared to growth otherwise expected over 2007 to 2020. See Chapter VIII and Appendix N of the Staff Report for additional information about our economic analysis.
>
> The California cap-and-trade program has been designed to be part of a regional trading system. The program design allows linkage with programs established by partner jurisdictions in the Western Climate Initiative (WCI) to create a regional market system. The goal of the regional program is to enhance individual jurisdictions' actions through collective action to reduce GHG emissions.

Support for Cap-and-Trade

H-20. (multiple comments)
Comment: As Education Director for West Coast Green I work with officials from the CPUC, CEC, Bay Area Air District, Bay Area governments, and many businesses and organizations dedicated to creating a clean economy for California. We thank you for your work crafting and implementing AB 32, and strongly believe that implementing a Cap-and-Trade program for California is the right step to take for our economy, our environment, and our communities. This policy could be strengthened by holding polluters accountable, auctioning pollution allowances, and creating a robust fund to help ratepayers in CA offset the costs of transitioning to a low-carbon economy. As I wrote for Climate Biz.com (http://www.greenbiz.com/blog/2010/09/01/why-were-asking-wrong-questions-cap-and-trade):

Cap and Trade Boosts Economy and Saves Money:
The most recent economic analysis released by the Western Climate Initiative in July, the proposed cap-and-trade program would provide net savings across the region of $100 billion by 2020 and spur long-term job growth. These cost savings are in addition to other benefits, such as improved public health, and economic development across a wide range of industries from investing in a cleaner, greener economy.

A host of recent reports has concluded that the costs of capping carbon would have a minimal impact on small businesses and S&P 500 companies alike, and would not compromise economic competitiveness or force jobs overseas. Likewise, the most recent EPA analysis of the American Power Bill found it would cost American families somewhere in the range of $100 a year, while California's new cap-and-trade program could actually provide net savings of $100 a year to the average family.

In fact, WCI calculates that enacting a cap-and-trade program could provide net savings to the whole region of $12 billion a year. While significant, this is still less than 1 percent of total economic activity in the region. This means the net impact to most businesses and consumers—in either cost or savings—will be largely negligible.

We urge you to continue your work implementing a robust Cap-and-Trade program for California by auctioning permits in a way that raises money for California businesses, families, and communities. (MANNLE)

Comment: Air Products encourages all measures that will mitigate the potential cost of allowances. Controls such as the three-year compliance period, modest compliance account balance requirements (vis-à-vis the incurred compliance obligation), flexibility in the amount and source of offsets, the ability to bank allowances and the use of the Strategic Allowance Reserve will all be necessary and the maximum flexibility in their application should be allowed. (APC)

Comment: Because of the state's revenue shortfalls, and both federal and private investor reluctance, I think it would be wise to put a price on carbon pollution as soon as possible, by increasing the share of permits that are auctioned. That may sound counterintuitive to opponents of fast implementation, but the undeniable facts are that the cost of implementation is at a historic low, and new opportunities are more greatly needed now than at any time since the 1930's. (POWERSD)

Comment: The benefits of regulation have vastly outweighed the costs. American business has always responded in the end by innovating and finding low-cost strategies to comply with environmental regulation. Don't set the bar so low that Californians lose out on the health and economic security benefits we could achieve by pressing industry to innovate. (TURNER)

Comment: There are a number of lifecycle-cost effective energy efficiency measures that could be implemented. There's no reason, economically, let alone climate change-wise, to delay implementing reductions in emissions by requiring upgrades in efficiency. Keep our energy money here in efficiency improvements versus exporting them for buying energy supplies. (MILLERKEN1)

Comment: There may be a dip in businesses wanting to come to California when the cap and trade is first implemented, however within a short time all the other benefits of setting up business in California will outweigh any draw backs originally focused on. (BUSSE)

Comment: Businesses based in or that do business in California should be held responsible for the damage they cause. Just as we pay recycling fees for the television sets and monitors we buy, the companies that produce environmental damage should be taxed as well. (LEVINSON)

Comment: We think this regulation supports the continuing building of a sustainable business economy, clean business economy within the state. There have been reports on the job. Our organization has actually done more of an anecdotal approach where we put together examples of our individual companies that have grown substantially. We did a survey. We found last year in the heart of the recession our membership grew the employee count by 20 percent, and are expecting more this coming year and the same next year. This is a direct result of policies like this. (CAEEIC)

Comment: Greenhouse emissions cause economic and environmental damage that already is in the trillions. Strong measures to prevent greenhouse emissions are needed to prevent the damage from escalating into extinction. (YEAGER)

Comment: Please put caps on greenhouse gas emissions. The oil companies should be investing in renewables. What standards we set will be followed by other states. We the people of CA need to show America what real leaders are made up of. Just say no to oil! (ZELICHOWSKI)

Comment: My main concern is that a full-fledged cap-and-trade system as earlier proposed would have significant utility rate impacts on top of the costs of implementing increased renewable resources and reducing greenhouse gas emissions. While my client's proposed projects show very faint indicators that we may be pulling out of the recession, I'm really worried that significant electric rate increases might push those projects out of California and prolong the recession. I'm thankful that CARB has proposed regulations implementing the goals of AB 32 that are very sensitive to reducing rate impacts to our business customers in this still fragile economic environment. Rate increases are unavoidable to meet our emission goals, but with the proposed implementation they are small and phased in over the next decade. I believe we all can work with the small annual rate increases that are required in order for California to continue to be a leader in environmental stewardship. (REC)

> **Response:** We concur that the cap-and-trade program and the broader Scoping Plan effort provide a model for action that can be taken at the Federal level and by other states individually and through regional action. By moving forward, California is both positioning our economy to benefit as climate action is taken internationally and promoting action throughout the country and the world.

Miscellaneous

H-21. (multiple comments)
Comment: Did CARB conduct any analysis on the impact of the regulation on different classes of water users (e.g. urban, agricultural, and environmental)? (DWR2)

Comment: Did CARB conduct an analysis identifying the economic and environmental impacts of this regulation, specifically based on impacts to water uses? More specifically, did CARB analyze the impacts on agricultural water users, who may have a disproportionately high level of water use compared to their electricity use? (DWR2)

Comment: Did CARB consider the economic and environmental impacts such as land use changes and crop-shifting that could result from this regulation’s possibly larger impact on agriculture, particularly in light of the assertion by federal power providers that they are not obligated to comply with this regulation, and the resulting incentives which would encourage additional water use on lands entitled to receive federal water deliveries? (DWR2)

> **Response:** Federal power providers are not exempt from this regulation for the electricity they delivery to the California grid. We analyzed the water ratepayer impacts from the regulation and found that, since the emissions associated with water distribution are included in the share of value returned to end-use customers through the electric distribution utilities, the impact on ratepayers is insignificant. We considered the average ratepayer in this analysis and acknowledge that different classes of ratepayers could face different impacts. We do not have information to determine how DWR will set rates for water customers once the regulation takes effect. Nevertheless, in Resolution 11-32,

the Board directed the Executive Officer to continue discussions with stakeholders to identify and propose, as necessary, during the initial implementation of the cap-and-trade program, potential amendments to the regulation, including distribution of allowance value associated with cap-and-trade compliance costs from using electricity to supply water and the expected ability of allowance allocation and other measures to adequately address the incidence of these costs equitably across regions of the State. Our responses to comments on environmental impacts are included in the responses to the Functional Equivalent Document.

H-22. Comment: DWR references comments from their earlier comment letters, and asserts that the environmental and economic impacts on DWR and water users have not been addressed.

Response: Our response to comments submitted by DWR is included as part of this Final Statement of Reasons and in the responses to the Functional Equivalent Document.

I. ELECTRICITY

This section includes comments and responses about the treatment of the electricity sector in the regulation. Major topics concern allocation to the electrical distribution utilities, treatment of imported electricity, renewable energy, combined heating and power facilities and other facilities with long-term contracts, and the electricity consignment auction. Comments concerning the use of consignment auction proceeds are found in the section entitled "Use of Auction Proceeds."

Allocation

General

<u>*Allocation to UCs*</u>

I-1. Comment: We're extremely disappointed that, while industry is given free allowances, the university and higher education in general and hospitals do not receive free allowances or any financial assistance or transition assistance under the proposed regulation. The proposed regulation will have a significant impact upon the university. We have five cogeneration plants and one large heat thermal plant that will be captured by the cap and trade regulations. We estimate that the cost of purchasing allowances on the auction will range between 7 million and 30 million per year, depending upon the actual cost of the allowances on the auction. We ask for transition assistance. (UC2)

> **Response:** While we understand the concerns of the UCs, we expect that the universities will be able to fully pass through the cost of carbon as fee increases or other options meant to pay for administrative overhead such as indirect costs in contracts and grants. Because there is not risk of leakage, the university does not require transition assistance. However, the university should expect to receive some remuneration for the increased cost of procuring electricity from the local distribution utilities that service the campuses. We are working closely with the CPUC and the POU governing boards to determine the appropriate level of remuneration. That said, at the October 20, 2011 meeting, the Board directed staff in Resolution 11-32 to coordinate with State universities and stakeholders to evaluate options for compliance, with amendments to the regulation as appropriate, including options for the use of auction revenue and to report back to the Board in summer 2012.

<u>*Allocation to Utilities NOT Efficient*</u>

I-2. Comment: Based on the HDPP situation, the auction mechanism as currently proposed in the Cap and Trade Rule conflicts from the outset of the program with AB 32's requirement that any ARB regulations be designed "in a manner that is equitable, seeks to minimize costs and maximizes the benefits to California" (H&S Code section 38562(b)(1)). For the outset in 2012, the proposed Cap and Trade program would distribute most GHG allowances for free, while requiring other entities like HDPP to purchase GHG allowances through the auction. It now appears that most electrical generators that purchase GHG allowances either had contracts that allowed them to pass the costs of GHG allowances through to the markets in 2012—or benefitted from subsequent government decisions allowing utilities to pay such costs in 2012, unlike HDPP and similar generators. Requiring HDPP or similar generators to purchase GHG allowances without the ability to pass through GHG allowance costs would place an inequitable burden on certain sectors and certain industries during 2012, in conflict with AB 32 and the principles underlying the proposed Cap and Trade program as approved by the Board. (HDPP2)

> **Response**: For the High Desert Power Project (HDPP) plants, the contract terms of concern are only an issue through 2012. ARB will be starting the first compliance period of the emissions trading program in 2013; therefore, HDD does not have to obtain allowances for their 2012 emissions. For 2013, HDPP has a mechanism in the contract structure to pass costs down.

Energy-Intensive Trade- Exposed

I-3. Comment: An issue related to third-party energy supply is the requirement to be a covered entity in order to receive an allowance allocation. Table J-75 states that facilities will receive a direct allocation of allowances for thermal energy imported from off-site. But, in order to be eligible for any allocation of allowances, a facility must be a covered entity or an opt-in covered entity. This means the facility must report at least 10,000 metric tons of CO_2e to qualify to opt-in. Consequently, a facility that purchases the majority of its thermal energy from a third-party will have very high indirect emissions, but no direct emissions, and may have an incentive to increase direct emissions in order to become a covered entity and be eligible for an allowance allocation related to off-site thermal supply. (CACC)

> **Response:** We disagree with this speculative assertion. A facility choosing to increase direct emissions in order to receive an allowance allocation would typically need to install new equipment to provide thermal energy to substitute for imported thermal energy. Furthermore, by becoming a covered entity, such a facility would have a compliance obligation for all direct emissions while receiving allowances for only part of the emissions. We believe, absent data to the contrary, that such a choice is unlikely to make economic sense.

GHG Cost Pass-Through, Verification

I-4. (multiple comments)
Comment: To provide a balanced implementation of its proposed Cap and Trade Regulations and avoid increasing global GHG and criteria air pollutant emissions, ARB should allocate allowances in a manner that recognizes the disproportionate and enterprise threatening burden that GWF faces relative to most other power producers. GWF's burden is the direct result of its efforts to comply with federal and state policies and the associated contractual obligations that GWF entered into. ARB could

accomplish this goal by amending the proposed Cap and Trade Regulations such that GWF receives allowances for its GHG emissions associated with its pre-AB 32 PPAs, declining throughout the 2012-2020 period at the same rate provided for the cement manufacturing industry. See proposed Cap and Trade Regulations, Table 9-2. Proposed amendments to the proposed Cap and Trade Regulations to achieve this goal are provided in Attachment A.

One of AB 32's core concepts concerns GHG "leakage", defined as "a reduction in emissions of greenhouse gases within the state that is offset by an increase in emissions of greenhouse gases outside the state." (Health & Safety Code sec. 385050). Section 38562(b)(8) requires ARB to minimize leakage in the way it crafts any market-based compliance mechanism, such as the proposed Cap and Trade Regulations. Additionally, section 38570(b)(2) directs ARB to design any market-based compliance mechanism to prevent any increase in the emissions of criteria air pollutants or toxic air contaminants. An alternative destination for California-produced petroleum coke (not otherwise consumed in California) is Asia (in fact, almost all California produced petcoke is exported). Petroleum coke that is exported to Asia instead of being consumed in California increases GHG emissions by the amount required to transport it to the end-user. In addition, criteria air pollutant emissions resulting from the consumption of additional tonnage of exported petroleum coke are almost certain to rise, since the emissions standards in Asia (particularly in China and India, two likely destinations of California petroleum coke) are not nearly as stringent as California's criteria pollutant standards.

By granting allowances (on a declining basis) directly to GWF for GWF's historical GHG emissions, ARB would fulfill its mandate to give leakage, criteria pollutant, energy/GHG intensity, and economic issues due consideration when designing the proposed Cap and Trade Regulations. ARB would treat GWF in a manner akin to other similarly situated entities that consume similar fuel. In addition, ARB would greatly reduce the economic impact of the proposed Cap and Trade Regulations to allow GWF to comply with its Pre-AB 32 PPAs, thereby recognizing that GWF's PPAs are a product of both federal and state law to promote domestic energy independence through the consumption of by-product fuels, like petroleum coke. Modify section 95870 as follows:

(a) Allowance Price Containment Reserve. On December 15, 2011, the Executive Officer shall transfer allowances to the Allowance Price Containment Reserve, as follows:

(1) One percent of the allowances from budget years 2012-2014,

(2) Four percent of the allowances from budget years 2015-2017, and

(3) Seven percent of the allowances from budget years 2018-2020.

(b) Advance Auction. On December 15, 2011, the Executive Officer shall transfer two percent of the allowances from budget years 2015-2020 to the Auction Holding Account.

(1) These allowances shall be auctioned pursuant to section 95910.

(2) The proceeds from the sale of these allowances will be deposited into the Air Pollution Control Fund and will be available upon appropriation by the Legislature

for the purposes designated in California Health & Safety Code sections 38500 et seq.

(c) Allocation to Public Utilities.

(1) Electrical Distribution Utilities. The Executive Officer will place an annual individual allocation in the holding account of each eligible distribution utility on or before January 15 of each calendar year from 2012-2020 pursuant to section 95892. Allowances available for allocation to electrical distribution utilities shall be 89 million multiplied by the cap adjustment factor in Table 9.2 for each budget year 2012-2020.

(2) Reserved for Natural Gas Distribution Utilities.

<u>(3) Owners and/or Operators of Electrical Generating Facilities not otherwise defined as Electrical Distribution Utilities. The Executive Officer will place an annual individual allocation in the compliance account of each eligible owner and/or operator of an electrical generating facility operating under a Pre-AB 32 Power Purchase Agreement on or before January 15 of each calendar year from 2012-2020 pursuant to section 95892. Allowances available for allocation to owners and/or operators of electrical generating facilities operating under Pre-AB 32 Power Purchase Agreements shall be drawn from the pool defined in section 95870(c)(1), and multiplied by the cap adjustment factor in Table 9.2 for each budget year 2012-2020, except for Pre-AB 32 Power Purchase Agreements for petroleum coke fueled generation, which shall be multiplied by the cap adjustment factor for Cement Manufacturing in Table 9-2.</u>

Modify section 95890 as follows:

(a) Eligibility Requirements for Industrial Facilities. A covered entity or opt-in covered entity from the industrial sectors listed in Table 8-1shall be eligible for direct allocations of California GHG allowances if it has complied with the requirements of the MRR and has obtained a positive or qualified positive verification statement for the prior year pursuant to the MRR.

(b) Eligibility Requirements for Electrical Distribution Utilities. An electrical distribution utility shall be eligible for direct allocation of California if it has complied with the requirements of the MRR and has obtained a positive or qualified positive verification statement on its sales number for the prior year pursuant to the MRR.

(c) Reserved for Natural Gas Distribution Utilities.

<u>(d) Eligibility Requirements for Owners and/or Operators of Electrical Generating Facilities not otherwise defined as Electrical Distribution Utilities. An owner and/or operator of an electrical generating facility shall be eligible for free, direct allocation of California GHG allowances if it has complied with the requirements of the MRR, has obtained a positive or qualified positive verification statement on its sales number for the prior year pursuant to the MRR, and is operating under a Pre-AB 32 Power Purchase Agreement</u>.

Modify section 95892 as follows:

(a) Reserved for allocation to electrical distribution utilities.

(b) Transfer to Utility Accounts.

(1) Investor owned utilities. The Executive Officer will place allowances in the limited use holding account created for each electrical corporation.

(2) Publicly owned Electric Utilities. At least 90 days prior to receiving a direct allocation of allowances, publicly owned electric utilities will inform the Executive Officer of the share of their allowances that is to be placed:

(A) In the publicly owned electric utility's compliance account, or

(B) In the publicly owned electric utility's limited use holding account.

<u>(3) Owners and/or Operators of Electrical Generating Facilities not otherwise defined as Electrical Distribution Utilities. The Executive Officer will place allowances in the compliance account of any covered entity from which an investor owned utility purchased electricity pursuant to a Pre-AB 32 Power Purchase Agreement, as defined by section 95802(a)(153)</u>. (GWFPS1)

Comment: Some electric utilities and independent power producers entered into contracts in the past that are still effective and that did not anticipate the proposed rule. The situation is similar (but opposite) for independent power producers who agreed to sell electricity to utilities under contracts that do not allow them to pass through the costs of allowances or offsets. In order to continue operating, these independent power producers are required to purchase allowances and offsets, but may not be able to pay for them within the pricing structure under existing contracts…The Proposed Rule does not take into account these contractual issues, or provide adequate remedies for the unintended costs borne disproportionately by parties to existing contracts. Some form of phase in, or relief from allowance requirements, is required in order to avoid significant, unintended consequences. (HOR)

Response: We realize that a portion of generators and industrial steam producers have reported that some existing contracts do not include provisions that would allow full pass-through of carbon costs associated with cap-and-trade. We have closely examined this issue, but do not believe it is the role of the regulator to negotiate contracts for parties engaged in an agreement, nor will we treat entities differently who have negotiated contracts. In several cases, we are aware of and are encouraged by knowledge of parties that are in the process of negotiations, or already have negotiated new contracts, to resolve this issue. Staff believes that bilateral contract negotiations provide the best resolution of this issue.

New Entry

I-5. (multiple comments)

Comment: The Utilities request additional clarification of how subsection 95853(e) applies to new entrants from the electric sector. While section 95812 includes the threshold for covered entities, which specifically includes electric generation facilities as well as the first deliverers of electricity, the amount of free allowances a new entity is eligible to receive is calculated based on section 95891 in the proposed regulation which outlines a calculation for allowance allocation only for the industrial sector. (MID1)

Comment: Section 95853(e) addresses the calculation of the triennial compliance obligation for new entrants, and notes that new entrants are eligible to receive allowances pursuant to both subarticles 8 and 9, which address allocation to both the Electrical Distribution Utilities and Industrial Facilities. However, this section also notes that allowances will be calculated pursuant to the provisions of section 95891, which deals only with the industrial sector. In order to clarify exactly how new entrants will be treated, and how their treatment will impact other Covered Entities and the overall allowance Budget, NCPA recommends that this provision be clarified. (NCPA1)

> **Response:** To clarify, 95853(e) only applies to new entrants in the industrial sector. Electricity generation facilities do not receive free allocations; thus, they would not apply to this section. There are no provisions in the regulation for new entrant utilities. A set number of allowances are allocated to utilities, and those allowances are divided up between the entities based on cost burden, energy efficiency, and early action. If a new utility were to enter the program, the division of allowances for all entities must be recalculated, requiring changes to all utility allocation. We believe this situation is unlikely, but are prepared to make the necessary changes if needed.

POU vs. IOU

I-6. Comment: While the Council does not offer an opinion on the option that the proposed California regulations proffer for publicly owned utilities that would allow these entities to simply use the allowances provided for compliance, the Council is concerned that the option could lead to reduced investment in AB 32 related activities by these entities, which could increase allowance prices for all in the long run. (BCFSE)

> **Response:** We share your concern, and made changes to section 95892 to ensure that allowances allocated to the distribution utilities must be used exclusively for the benefit of retail ratepayers and in a manner that is consistent with the goals of AB 32.

I-7. Comment: LADWP strongly supports the provision that allows a publicly owned electric distribution utility (POU) to deposit administratively allocated allowances directly into its compliance account. All entities should have a reasonable means to comply with the Cap and trade regulation in a manner that accommodates their respective business models and compliance strategies. By including this provision, ARB has correctly acknowledged that the electric sector remains only partially deregulated after AB 1890, Chapter 854, Statutes of 1996, which was originally intended to introduce competition to California's electricity sector. (LADWP1)

> **Response:** We agree. Thank you for your support.

I-8. Comment: ARB has been sensitive to the diversity of the electric distribution utilities, many of which are publicly owned utilities that operate for the exclusive benefit of their retail ratepayers, provide the sole source of electric service within their service territories, own their generation assets on behalf of their retail ratepayers, and finance their investments in a manner entirely different from investor-owned utilities. As such, imposing auction design features on vertically integrated POUs is an unnecessary additional step that does not provide any value to POU electric ratepayers, nor to California overall. Many utilities, such as LADWP, own and operate generation to meet all of the load requirements. It does not make sense for LADWP to receive administratively allocated allowances, sell them in an auction, only to turn around and buy them back again. This is not, in LADWP's view, a "carve out" or "exemption" for POUs. Instead, it is a fundamental and critical need, due to the business structure. The Cap and trade program must be designed to work for all participants, including POUs, even if that means the regulation includes provisions like this one that efficiently accommodate different business models and compliance strategies. (LADWP1)

Response: We agree. Thank you for your support.

I-9. (multiple comments)
Comment: As proposed in the Proposed Rule, customers of IOUs have to pay for their allowances through higher electricity prices, while POUs do not. ARB does not explain this apparently arbitrary distinction between types of utilities. Is there are rationale for this disparate treatment? Does it have a purpose? AB 32 provides no basis or support for this distinction. (HOR)

Comment: CARB asserts that the allowance allocation system is fair within and across sectors. If so, fairness dictates that IOUs should be subject to the same rules as POUs with respect to the mandatory consignment of allocated allowances, which is not the case under the Proposed Regulation. Because of these unequal rules, any adverse impacts of the auction process will fall far more heavily on IOU customers than POU customers. (SCE1)

Comment: Publicly-owned utilities (POU) must not be allowed to reserve directly allocated allowances to meet the emission reduction obligations of their generation. Section 95982 exempts POUs from a requirement to make all allowances that it has received through direct allocation available for sale at auction. This exemption permits POUs to use directly allocated allowances to cover emissions by their own generation, while other generation resources will have to purchase compliance instruments. The staff report asserts that this exemption is warranted on the grounds that POUs have a different business model than IOUs, and no not compete with independent power producers. However, those statements are not categorically true, as POUs do frequently participate in wholesale power markets to sell surplus power. To allow POUs to reserve directly allocated allowances to cover emission reduction compliance of their own generation would give them an unacceptable advantage over independent power producers in these wholesale markets. WPTF therefore urges that the regulation be modified to require POUs to monetize all allowances received through direct allocation and to acquire allowances for their own generation and imports through auction. (WPTF)

Comment: Fairness dictates that CARB treat IOUs and POUs equally in the allowance auction. CARB staff states that "the allowance allocation system is equitable within and across sectors of the California economy." However, by requiring the IOUs to consign their allowances to auction without requiring the same of POUs, the proposed regulation is inconsistent in its treatment of IOUs and POUs. POUs have the choice to consign their allocated allowances to auction or place the allocated allowances directly in their Compliance Accounts. SCE believes POUs and IOUs should be subject to the same rules under this regulation. Both IOUs and POUs are freely allocated allowances, some of which will be used for direct compliance and some of which will be used for compliance with regard to purchased power. Thus, SCE and other IOUs should be afforded the same flexibility in auction participation as POUs, and be permitted to either consign allowances to auction, or transfer allowances to their compliance accounts. Alternatively, SCE suggests that POUs should be subject to the same rules as IOUs with regard to their freely allocated allowances. If 100 percent of the direct allocation for IOUs must go to their Limited Use Holding Accounts for consignment in auction, then the same should apply for POUs. This is true for several reasons.

First, CARB's primary reason for requiring IOUs to consign allocated allowances to auction is to ensure that the "amount of value given to distribution utilities is transparent to the public, and that this value is used on behalf of utility ratepayers." This reasoning applies just as strongly to POUs and their customers.

Second, SCE believes that the rate impact of the cap and trade program should be felt equally by both IOU customers and POU customers to avoid perception issues and cross-customer class distortion. SCE supports the process of monetizing its direct allowance allocation; a rise in rates will increase energy consumption sensitivity, while periodic rebates can serve to minimize customer hardship. However, POUs should be required to similarly adjust their rates in order to maintain relative parity between IOU and POU rates. Otherwise, customer confusion or dissatisfaction may result. IOU rates will likely be much higher in dollars per kilowatt hour than POU rates, and while the periodic refunds from IOUs should offset the rate increase, it is unlikely that customers will see their separate refunds as directly related to their rate increases. Moreover, IOU customers will be doubly disadvantaged as the IOUs are forced to establish and implement what will likely be a costly mechanism for returning this allowance value to their customers, while POU customers are spared this additional cost.

Third, CARB's unequal treatment of IOUs and POUs will negatively affect the availability of allowances during the crucial early days of the auction. If POUs can withhold allowances from the auction, IOUs will be placed at a competitive disadvantage. Without the consignment of allowances by industry and all utilities, the total available allowances in each auction in the first compliance period could be limited to those consigned by IOUs and a minimal amount placed in the auction by CARB. IOUs will be forced to compete for these allowances with other covered entities, voluntary participants, and opt-in participants. This could crowd IOUs out of the market in the auction while POUs need not enter the auction in the first place, creating an unfair advantage for POUs. Additionally, if the market is aware that IOUs are forced into the secondary market to purchase allowances, prices will likely soar, causing an undue burden on electricity customers. Especially during the first compliance period, requiring POUs to consign their allowances to the auction will increase the likelihood that the markets are broad enough to prevent this burden.

To address this inequality, CARB should provide the same rules for IOUs and POUs. CARB can modify the IOU rules to parallel those for the POUs and allow IOUs to retire some allocations directly into their compliance accounts. Alternatively, CARB can modify the rules for POUs such that they too must auction off and then re-purchase their allowances. (SCE1)

Comment: The proposed regulation should treat publicly owned utilities similar to other electricity market participants and other load serving entities. The proposed regulation has arbitrarily set up different rules for publicly-owned electric utilities (POU) than for investor-owned electric utilities (IOU), giving POUs unfair market advantages, and giving POU customers different GHG price signals than are required to be given to IOU customers. The cost of all electricity consumed in California should equally reflect the real cost of carbon. The proposed regulation requires first-deliverers of out-of-state electricity and investor owned utility generation to purchase allowances through the auction or purchase offsets. If POUs are given free allowances directly that they can apply to their generation, while other generators must purchase allowances in wholesale markets, there is clearly a mismatch in the treatment of similarly situated generators with potentially uncertain effects on the electricity market. If it is important that IOUs must auction off allowances to avoid interfering with competitive markets, it would seem equally important for POUs to do the same. It is odd that the regulation requires IOUs, who are already subject to State regulation through the CPUC, to document how the allowance value is used, but does not require POUs, whose actions have no State oversight, to do the same. POUs have no oversight from the State regarding the use of allowance value except through ARB regulations. These provisions, applicable only to POUs, are arbitrary, discriminatory, and have no basis in law or fact to support them. There is no provision in AB 32 that justifies it, and the ISOR offers no compelling justification. The proposed regulation should be corrected to require publicly owned utilities to purchase allowances through the auction or other means for their out-of-state electricity purchases and owned generation in the same manner as for other generators. Modify section 95892(b) "Transfer to Utility Accounts" as follows:

> (1) Electric Distribution Utilities. The Executive Officer will place allowances in the limited use holding account created for each electrical distribution utility.
> ~~(1) Investor-owned utilities. The Executive Officer will place allowances in the limited use holding account created for each electrical corporation.~~

~~(2) Publicly owned Electric Utilities. At least 90 days prior to receiving a direct allocation of allowances, publicly owned electric utilities will inform the Executive Officer of the share of their allowances that is to be placed:~~
~~(A) In the publicly owned electric utility's compliance account, or~~
~~(B) In the publicly owned electric utility's limited use holding account.~~
(SEMPRA1)

We also would ask the Board to eliminate the dichotomy in the allocation of allowances for the state's electric utilities. The cost of electricity consumed in the state should equally reflect the real cost of carbon. Unfortunately, the proposed regulation on the use of allowance revenues for IOUs and POUs would put IOU customers at a disadvantage. (SEMPRA1, SEMPRA2)

Comment: The proposed regulation should provide multi-jurisdictional retail providers with the same compliance flexibility that is granted to POUs. The proposed regulation currently requires all IOUs (including MJRPs) to place all of their allowances directly into the auction. In contrast, POUs would be able to directly use their allowances to meet their own compliance obligation and place the remainder into the auction. For the purposes of these regulations, MJRPs are more akin to POUs insofar as the MJRPs are vertically-integrated entities operating their own balancing authority areas. Furthermore, MJRPs are subject to regulatory jurisdiction by entities other than the California Public Utility Commission (CPUC), and are therefore subject to a different set of resource planning requirements than are the other California IOUs. Accordingly, to accommodate these structural distinctions and avoid direct conflict with its regulatory mandates under other jurisdictions, MJRPs should be granted the same compliance flexibility as are the POUs. We suggest that ARB revise that distinction to be not about investor-owned versus publicly-owned, but one of vertical integration. (PACIFICOR1, PACIFICOR2)

Response: We understand the concerns; however, POUs and IOUs operate differently with respect to electricity generation. POUs generally own and operate generation facilities which they use to provide electricity directly to their end-use customers. In order to minimize the administrative costs of the program to the POUs, and recognizing that directly allocating the allowances to the POUs does not distort their economic incentive to make cost-effective emissions reductions, we determined that it would be prudent to allow POUs to surrender directly allocated allowances without participating in the auction process. IOUs, on the other hand, have contracts with electricity generators that do not afford the IOUs the same level of control over the capital investments and operating decisions of the generation facility. We are concerned that the terms of these contracts could be adversely affected by allowing the IOUs to directly surrender allowances on behalf of their counterparties, which could lead to some foregone cost-effective emissions reductions. Instead, by requiring the IOUs to consign the allowances at auction, the electricity generators will be sure to have a strong incentive to pass their GHG costs back to the IOUs who will then be able to use their share of the auction revenue to reduce the ratepayer burden in a manner that is consistent with the goals of AB 32.

In considering the exact amount of value to allocate to each local distribution utility, we took a cost burden approach. The framework was formed by holding a series of public meetings and obtaining input from stakeholders. Our working consensus was laid out in the regulation. If you would like to view the presentations for these public proceedings please visit: http://www.arb.ca.gov/cc/capandtrade/meetings/meetings.htm#publicmeetings.

Sectoral Allocation and Interaction

I-10. Comment: LADWP appreciates the ARB's proposal to administratively allocate allowances to the electric sector as a whole in an amount that is expected to cover the sector's native load compliance burden while the electric distribution companies expand their renewable energy portfolios and pursue aggressive energy efficiency standards. It is important for the electric sector's emissions budget to be set at the start of the program in order to provide regulatory certainty. However, should there be major shifts in emissions that result from an earlier than expected economic recovery, increase in load associated with electric transportation or multi-year droughts, LADWP supports an overall reevaluation of the electric sector's allowance budget and upward adjustments as appropriate to ensure that the electric ratepayers are protected from undue economic harm. (LADWP1)

Response: We will continue to evaluate the appropriateness of allowance allocation and make recommendations to adjust if necessary. Any adjustment would require a regulatory amendment.

I-11. (multiple comments)
Comment: Utility sector allowance allocation should include cogenerated electricity that is sold to the grid. Subarticle 8 of the proposed regulation states that allowances will be administratively provided to electric distribution utilities in the electricity sector, in an amount equal to 89 million metric tons multiplied by the cap adjustment factor in Table 9.2 in each budget year. This is equivalent to 89 million metric tons of allowances in 2012, declining each year thereafter to contribute to meeting the AB 32 target of achieving 1990 emission levels in 2020. SMUD strongly supports the proposed administrative allocation of allowances to electric distribution utilities on behalf of their customers, but the amount of allowances so provided is key. It is our understanding that the allowances for the electricity sector so allocated are intended to be set at 90 percent of the sector’s 2008 emissions, including emissions from cogeneration electricity sold to the grid. However, the 89 million metric ton number does not yet include the emissions associated with cogeneration electricity sold to the grid. SMUD believes that this addition is essential in order to reduce impacts on electricity customers. (SMUD1)

Comment: PG&E recommends that the quantity of allowances allocated to the electric sector via utilities be increased by 8.7 MMT for an electric sector total of 97.7 MMT/yr in 2012 and requests that section 95870 (c) be revised to reflect this. The increase reflects utilities' purchases of electricity from combined heat and power (CHP) facilities. PG&E's proposed 8.7 MMT adjustment associated with CHP generation delivered to the grid was quantified by estimating electric local distribution company (LDC) purchases from CHP and multiplying them by a "payment" heat rate derived from the recent settlement proposed by key QF trade organizations and the IOUs. For a heat rate, PG&E proposes an 8125 Btu/kWh rate, which is on the low end of a number of "payment" heat rates included this settlement. Assuming natural gas as a marginal fuel and current estimates of CHP grid deliveries, this translates to an additional allocation of allowances to the electric sector of 8.7 MMT per year. (PGE1)

Comment: "Allowances available for allocation to electrical distribution utilities shall be 89 million multiplied by the cap adjustment factor in Table 9.2 for each budget year 2012-2020" (section 95870(c)(1)). NCPA believes that this number should be revised to include an additional 8.7 MMT from combined heat and power (CHP), for a total sector allocation of 97.7MMT. NCPA supports the use of 97.7 MMT as the minimum number allowances to be freely allocated to the Electrical Distribution Utilities.
NCPA recommends that section 95870(c)(1) be modified to also include 8.7 MMT of additional allowances that are attributable to CHP generation that is purchased by utilities (as opposed to used for industrial purposes). The 8.7 MMT is derived by taking a reported 2,562 MW of statewide CHP purchases by electric utilities, and using a 8125 Btu/kWh heat rate, which translates into 9.7 million metric tons of emissions, multiplied by 90 percent, which results in 8.7 million metric tons of additional allowances to address utility purchases of electricity from CHPs. The cost of CHP generation purchased by utilities is properly allocated to the electrical distribution utilities on behalf of their customers. (NCPA1)

> **Response:** We agreed and changed the regulation accordingly. We explained the new allocation to the electricity sector in "Appendix A: Staff Proposal for Allocating Allowances to the Electric Sector," which was posted to the rulemaking website on July 27, 2011.

I-12. Comment: Make the following change in Table 9-2 within section 95891 to clarify that despite the heading, the factors in this category apply to the electricity sector, too: "Cap Adjustment Factor (c) for <u>Electric Sector and </u>All Other Industries." (NCPA1)

> **Response:** We modified the table to be more general and include the electricity sector as follows: Table 9-2: Cap Adjustment Factors for <u>Allowance Allocation.</u>

I-13. Comment: The reason ARB gives for its decision to allocate all allowances to utilities is that they are in the best position to monetize the value of the allowances and return that value to their ratepayers. Stated differently, the utilities are in the best position to obtain revenues for allowances from other industrial sectors and use those revenues to reduce electricity users' costs. This represents a policy decision to exact revenues from regulated parties, and direct those revenues to the reduction of electricity rates for electric utility ratepayers. This concept is bizarre, and has no foundation in AB 32. On what legal or policy basis should utilities be allocated allowances that they essentially sell to other industries in order to reduce ratepayers' electric bills? A system that allocates a limited resource to one segment of the economy at the expense of other sectors is a recipe for disaster. The other segments of the industry will not be able to compete with utilities for allowances. In addition, the costs of the program will be artificially skewed toward non-utilities. (HOR)

> **Response:** Allocation to electricity utilities was chosen as the preferred method to return the allowance value to those affected by this program. Because most industrial facilities and Californians use electricity, returning allowance value via electricity utilities is the best alternative to reduce the cost burden of this program. We modified the regulation to include 95892 that demands electric utilities use allocation value to benefit ratepayers, which includes both industry and Californians. Additionally, industrial facilities receive allowances corresponding to production or energy use, see section 95891.

I-14. Comment: There is another reason that this allocation is inequitable. Utilities are uniquely positioned to purchase (and in fact are required to purchase) renewable energy. The purchase of renewable energy is the only option (other than reducing operations) for continuing to operate at historical levels while complying with a greenhouse gas emissions limit. Other entities have limited abilities to avail themselves of renewable energy, because such energy is usually built to order for utilities. Nearly all of such sources are supported by, and sell their power exclusively to, utilities. So, utilities are among the only entities able to offset their constrained greenhouse gas emissions limits with alternative sources. And yet, the Proposed Rule places the allowances in the hands of the utilities, at the expense of all other market sectors. Utilities will be able to supplement their generation sources to mitigate the costs of allowances, while their competitors and other market segments will have only a limited ability to do so. (HOR)

> **Response:** We disagree with this comment and believe that all facilities have strategies to reduce greenhouse gas emissions. The compliance pathway analysis of the Staff Report details reduction opportunities for the various industrial sectors of California. Additionally, industrial facilities will also receive allowances to assist in the transition to a lower carbon economy and to minimize leakage consistent with the mandates of AB 32.

I-15. Comment: Lest you think that consumers are the beneficiaries of this inequitable arrangement, consider the second compliance period. In the second compliance period, all fossil fuels will be subject to greenhouse gas emissions limits and to the allowance program. Beginning on January 1, 2015, gasoline, propane, and all commercial and industrial products will reflect a price for greenhouse gas emission allowances that are generated by competition with electric utilities. When consumers use too much electricity, the cost (or shortages) will show up in the gasoline prices paid by other consumers. At that point, all California citizens will be paying extra costs in goods and services in order to subsidize electricity rates. There is nothing about such a system that is equitable. (HOR)

> **Response:** A central aspect of the cap-and-trade program is the existence of a price signal to drive reductions in greenhouse gas emissions. Reductions will come from all covered sectors, and we expect that consumers will respond to carbon prices by choosing the bundle of goods and services that provides them with the greatest affordable benefit. To assist consumers in the transition to a lower-carbon economy, we determined that it is appropriate to return a fraction of the total allowance value to consumers. Because most industrial facilities and Californians use electricity, returning allowance value via electricity utilities is the best alternative to reduce the cost burden of this program. We modified the regulation to include section 95892 that directs electric distribution utilities to use allocation value to benefit ratepayers, which includes both industry and Californians.

I-16. Comment: Increase the percentage of allowances auctioned to emitters and utilities. The California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) recommended to CARB a transition to 100 percent auction for the electricity sector by 2016. It is not entirely clear from CARB's Proposed Rule section 95870(c)(1) and Table 9.2 what percentage is being freely allocated versus auctioned, but it appears to be a far cry from 100 percent by 2016. (CONSUMERSUNION)

> **Response:** We disagree with this comment and believe the current method of increased free allocation is the best approach. See Section H of the Staff Report.

Transportation Electrification

I-17. (multiple comments)
Comment: The proposed regulation must account for shifts in achieving GHG emissions reductions from the transportation sector to the electricity sector.

Transportation electrification is widely recognized as an important means for achieving net societal GHG emissions benefits, even though coal-fueled power plants provide some portion of the energy supply. However, a lower-carbon economy with greater reliance on electric vehicles will result in a commensurate increase in the demand for electricity as a transportation fuel.

Moreover, the burden created by this beneficial fuel switching will be borne disproportionately among different utilities. Increases in electricity demand driven by transportation electrification will not produce any greater compliance costs or obligations for deregulated utilities that have largely divested their fossil generation and primarily offer distribution services. In contrast, vertically-integrated utilities that still fall under traditional regulation will continue to operate and build new generating units to meet increases in electricity demand. The resultant electricity demand from such beneficial activities as transportation electrification will compound the existing GHG compliance obligations of these utilities.

PacifiCorp recommends that ARB include in its proposed regulation a robust, flexible mechanism for adjusting a utility's overall compliance obligation as the burden for achieving GHG emissions reductions from the transportation sector shifts to the electricity sector. (PACIFICOR1)

Comment: The Utilities request that CARB address the potential for increased use of plug-in electric vehicles and the impact of this on all aspects of the cap and trade program. The Utilities believe additional allowances should be made available to electric distribution utilities commensurate with the covered entity's growth in emissions due to infiltration from the vehicles, as further identified by the California Public Utilities Commission in a recent white paper. (CPUC, Policy and Planning Division, Staff White Paper: "Light-Duty Vehicle Electrification in California: Potential Barriers and Opportunities" May 22, 2009). (MID1)

Comment: Growth resulting from vehicle electrification should be accompanied by a commensurate allocation to protect utility customers from increased compliance costs. PG&E is concerned about the interaction of the Cap and trade program with other policies that encourage vehicle, port, off road equipment, and goods movement electrification. Electric fuel will increase statewide electricity consumption, and associated GHG emissions. While society will experience lower overall emissions, increased electric sector emissions will result in higher electricity costs, which utility customers will bear through increased rates. PG&E is concerned that this circumstance may create disincentives for utilities and their ratepayers to support transportation technologies that use electricity, reducing the potential to achieve the benefits associated with transportation sector electrification. PG&E agrees with the CPUC's assessment that "failure to make available additional allowances to the electricity sector due to electrification risks overburdening ratepayers with the cost of transportation sector emissions." To ensure that electric fuel is encouraged, consistent with the goals of AB 32, PG&E recommends that ARB address increased costs to the electric sector through allocation of allowances in the Cap and Trade program. PG&E believes that allowances associated with electric fuel should be returned to electric ratepayers, under the guidance of the CPUC and municipal utility boards, so that the value of allowances flow directly to the customers who bear the carbon costs associated with electric fuel. (PGE1)

Comment: Cross-sector shifts of emissions should be accounted for in the allowance allocation policies. Perhaps the largest potential for emissions reductions in the State in the long-term lies in electrification of the transportation sector. However, these reductions are by no means assured given the high costs of infrastructure investment that the electricity sector and customers will need to make, as well as the costs of the vehicles themselves. Given these up-front cost-barriers, significant incentives will likely be needed for consumers to be willing to adopt electric vehicles en-masse. While the

ARB has stated it intends to leave the allowance value associated with the transportation sector to the legislature to determine how best to appropriate that value, SMUD strongly encourages the ARB to consider how the allowance value associated with those transportation emissions that are shifted to the electric sector could be used to defray infrastructure cost upgrades and incent electric vehicle uptake. Just as distribution utilities are looked to for delivering effective incentive mechanisms for energy efficiency and rooftop solar in this state, so too will the distribution utilities play a central role in encouraging electric vehicles. As regulated entities, distribution utilities can be required to spend any allowance value associated with transportation electrification on programs, rate incentives, and infrastructure upgrades which support this electrification, thereby encouraging more rapid adoption of the technology.

In addition to providing some incentive, a shift of allowance value will assure that increased emissions obligations that result from increasing electric transportation loads do not create an undue cost burden on the utility's other consumers. If electric transportation loads drive increased compliance obligation, electric utilities will be forced to pass these costs on to our customers on top of the infrastructure costs we must come up with to enable these vehicles in the first place. The amount of allowances that should be transferred from the transportation sector should, at a minimum, cover this increased compliance obligation, but ideally should cover both this as well as an amount up to the allowance value that is avoided in the transportation sector as a result of the electrification activity. (SMUD1)

Comment: Electrification of public transportation (ISOR, p. II-33), ports, and personal vehicles could have a net positive impact on the State's overall emissions reductions. However, this same impact is likely to result in an increase in the emissions associated with the electricity sector that are not accounted for in any of the current emissions accounting methods under consideration. Electrification and the development of a more robust, secure, and reliable electric vehicle infrastructure are not simple matters. However, they are a real part of meeting the goals of AB 32 and will present real impacts for electric utilities' compliance with the Cap and Trade Program. Accordingly, NCPA urges the Board to direct staff to work with stakeholders to further review and address this issue, and provide 15-day proposed revisions for the public's consideration during the first quarter of 2011 for inclusion in the final regulation. (NCPA1)

> **Response:** We are aware of the increased interest in the electrification of commercial and personal vehicle fleets. However, we do not expect that the growth in this electric load will significantly impact utility costs by 2020. We will monitor the electrification of transportation and will address this concern if it arises in the future.

Allocation Structure

I-18. (multiple comments)
Comment: Recognize the historically low emissions of SFPUC's electric system in allocating allowances to the electric sector. SFPUC has the lowest GHG emissions per

megawatt hour (MWh) of any large California electric utility. The current proposal fails to properly recognize the City's low GHG footprint and potentially loads the City's municipal utility operations with a greater cost burden than emissions-intensive utilities. The initial ARB staff proposal has not benefited from public discussion on the issue of how to allocate allowances to the electric sector. Subsequent to the release of the staff proposal, the SFPUC became aware that ARB staff, working with a selected group of electric utilities (the Joint Utilities Group or JUG), is now proposing an entirely new allocation mechanism that has yet to be made publicly available for comment or review.

After a review of the JUG proposal, it is clear that it unfairly rewards those utilities which have historically had high GHG emissions at the expense of utilities such as SFPUC. Paradoxically, SFPUC, despite having amongst the lowest GHG emissions rate of any public utility in California, could find itself in the position of needing to buy allowances to meet its demand during times of drought conditions and to meet future load growth. This represents a significant departure from ARB's original proposal to allocate allowances based on a combination of utility sales and historical emissions, an allocation method much more consistent with rewarding past actions to reduce GHG emissions. Under the JUG proposal, SFPUC would forego potential revenue from allocations it should receive. Requiring SFPUC to buy allowances while high emission utilities are relieved of that cost would not be equitable, and in effect would create a situation in which SFPUC would subsidize energy efficiency and renewable energy investments by electric utilities which use much higher GHG-producing fuel sources. We therefore recommend that ARB:

A. Refrain from endorsing the JUG proposal at this time until interested parties have had time to review and analyze its methodology and proposed allocation. These detailed proposals represent a fundamental change from the guiding principles outlined in the Initial Statement of Reasons (ISOR), and therefore warrant proper public process. The JUG proposal also grants allowances, in contravention of the requirements of AB 32, for "early action" that is already required by State law.

B. The Board should direct ARB staff to focus on the stated goals of any allocation proposal and the requirement that it; "provide proper incentives, (be) affordable for all utilities, and (be) considered equitable."

C. The City encourages ARB to include as the stated goals of the JUG to:

- Ensure that utilities with lower GHG emissions have sufficient allowances to provide reliable service and meet their needs.
- Ensure that utilities with lower GHG emissions do not see increased rates as a result of Cap and Trade implementation (The Allocation-Cost Burden).
- Afford utilities with lower GHG emissions a proportionately greater net benefit (i.e., a larger Allocation-Cost Burden) from the allocation process than utilities with higher GHG emissions.

D. In order to recognize and reward electric distribution utilities with demonstrated low GHG emissions, and to provide an incentive for other utilities to continue to reduce their GHG emissions, the City encourages ARB to establish a minimum allocation for all electric utilities. A minimum allocation that is below

the 2020 target for the electric sector (specifically, 200 metric tons per gigawatt-hour) will ensure that low GHG utilities will be rewarded for their past and current efforts and provided with a revenue source to support growth, fund further renewable and energy efficiency programs and investments and mitigate rate impacts on their customers.
E. ARB should give staff the necessary discretion to craft appropriate modifications to any proposed allocation mechanism finally adopted.
(SFMAYOR1, SFPUC1, SFPUC2, SFPUC3)

Comment: Allocation of allowances among electric distribution companies should strongly and visibly reflect early action, and there should be consideration of transitioning toward a replicable, sales-based allocation structure. The proposed regulation is at present, silent about how the allowances administratively provided to the electric sector are to be distributed among the various electric distribution utilities in the state. In May of this year, ARB staff indicated that the thought at that time was to distribute such allowances primarily based on sales, similar to the output-based approaches proposed for many individual industrial sectors. SMUD has consistently stated a preference for an allowance structure that reflects early action to reduce GHG emissions, as many utilities that have taken these actions have already incurred and passed on to their ratepayers the costs of these early emission reductions. In addition, SMUD has supported allowance structures that transition toward greater reliance on sales over time, to provide a more powerful incentive to reduce use of higher GHG resources. Specifically, SMUD has supported a structure that was based initially 75 percent on historic emissions and 25 percent on sales, transitioning by 2020 to a structure that is based 25 percent on historic emissions and 75 percent on sales. This is similar in structure to that recommended to the ARB by the California Energy Commission and the California Public Utilities Commission, the two energy agencies with the greatest experience with the electricity sector.

However, SMUD understands that staff is currently considering basing the allocation of allowances among utilities on projected emissions resulting from utility resource plans and state-required investments in renewables and efficiency. While we can support this approach, SMUD believes that this structure is not easily replicable beyond 2020 or nationally because the development of resource plans from now on will be altered if those doing the planning understand that their allocation of cap and trade allowances will be affected by how they do these plans. This implies potential risks to California if a similar structure is adopted nationally, as it would likely leave California entities with lower than expected allowances in a national market, and it is unclear whether California’s general early action to reduce GHG emissions would be recognized. Strong advocacy of national complementary policies may help to reduce these risks, but will not mitigate them entirely. To address these issues, SMUD believes that the final structure must include a strong, visible, ‘early action’ component, not just to recognize such actions within the currently proposed cap and trade in California, but also so that if the approach is adopted nationally, there will be precedent to recognize California’s early action. In addition, SMUD believes that there should be further consideration of a transition to an approach based more on sales, similar to that proposed for the industrial sectors. (SMUD1)

Comment: The allocation of allowances among utilities, as laid out in Appendix 1. In that discussion, we believe that we should shoot for a structure that is replicable beyond 2020 and nationally, and one that includes a strong visible early action component to reduce risks to California in a national situation. We also believe there should be further consideration of a transition to a sales-based approach, similar to the output-based approach that's being used in the industrial sector. (SMUD2)

Comment: The allocation of emissions allowances to electrical distribution utilities should be based on the distribution utilities' projected costs of compliance. The proposed regulation does not specify how allowances would be allocated among the Electrical Distribution Utilities that are eligible for direct allocation from the Air Resources Board (ARB). Assuming an allowance trading regime is included in the Cap and Trade Program, PacifiCorp supports ARB's separately-proposed methodology to allocate allowances based on the distribution utilities' projected compliance burden. Under this approach, a utility will receive allowances based on its forward-looking compliance obligation, which is primarily a function of the overall expected emissions attributable to serving the utility's customers, net of partial credit for greenhouse gas reductions due to early action with renewable resources and energy efficiency.

Though PacifiCorp continues to have significant reservations regarding the use of state- and/or regional-based allowance trading regimes as the principal means of reducing carbon emissions, the Company strongly supports ARB's adherence to an emissions-based allowance allocation methodology, as opposed to a sales-based approach. An emissions-based methodology will help mitigate increases in electricity costs attributable to the Cap and Trade Program for customers of utilities with higher emissions profiles, as they transition to a lower-carbon portfolio. Under ARB's proposal, these utilities would be allocated allowances to either (1) cover emissions from utility-owned generation or (2) be sold by the utility at auction, with proceeds used to offset the higher costs of energy purchased at market. This proposal also helps utilities like PacifiCorp with a significant share of customers under the CARE program manage the disproportionately-high rate impacts of the Cap and Trade Program to its low-income demographic.

PacifiCorp continues to advocate that if an allowance trading regime is to be implemented within a greenhouse gas compliance program, allowances should be allocated based purely on emissions, and the Company remains firmly opposed to a sales-based allowance allocation approach. A sales-based approach awards windfall profits to low- and zero-emitting utilities in the form of a wealth transfer from utilities like PacifiCorp with higher emissions profiles; this scheme would only further exacerbate the rate impact on PacifiCorp's low-income customers in California. In addition, PacifiCorp's preference is that ARB does not allocate allowances according to either early action with renewable resources or energy efficiency gains, as ARB currently proposes. However, PacifiCorp feels that ARB's proposed allocation method reflects a reasonable compromise among the California utilities. (PACIFICOR1, PACIFICOR2)

Comment: The Council notes that the Air Resources Board may adopt an allowance allocation structure in the utility sector that is based on current, static, utility procurement plans. The Council does not believe that such an approach is replicable at a national level, or after 2020 in California, as the development of procurement plans from the point of adoption onward—whether at a state level or nationally—will be altered if those doing the planning understand that their allocation of cap and trade allowances will be affected by how they do these plans. (BCFSE)

Comment: LADWP generally supports a forecasted emissions-based methodology to allocate allowances in a manner that reflects the forecasted emissions cost burden for each load serving utility, and incorporates the expected benefits of energy efficiency investments, so that energy efficiency accomplishments are rewarded. LADWP supports an allocation methodology that does not leave any electric utility "short" of emission allowances so long as that utility continues to make emission reductions in alignment with the State's renewable energy and energy efficiency requirements. (LADWP1)

Comment: LADWP firmly rejects any methodology that would incorporate a retail sales-based allocation, in that such allocation fails to acknowledge the cost burden associated with the Cap and trade program and introduces disparate and discriminatory treatment between electric distribution utilities. LADWP does not support updating of the intra-sector allocation between electric utilities between 2012 and 2020, since this is a fairly short period and any shifting of allowances between utilities could cause unnecessary disruptions to investments. If any reassessment of the sector's allowance budget results in an increase to the sector's overall allocation, such increase should be equitably applied to all electric distribution utilities. (LADWP1)

Comment: The administrative allocation of allowances to the electric sector must balance the desire to reward early actions to reduce emissions without penalizing electric utilities for geographic or historical circumstances that dictate the emissions of their current generation portfolio. (LADWP1)

> **Response:** We modified the electric utilities allocation and provided a description and rationale for the approach in Appendix A: Staff Proposal for Allocating Allowances to the Electric Sector with the 15-day changes to the regulation. We modified sections 95870 and 95892 and inserted table 9-3. The allocation methodology is non-updating and based on cost burden, energy efficiency, and early action—as defined by investment in renewables during the period 2007-2011. We believe that this approach fairly apportions value to the electric distribution utilities in a way that compensates retail customers for their cost, providing transition assistance, while maintaining a strong incentive for distribution utilities to make investments toward lowering their emissions profile. We believe that this approach is replicable for the beyond 2020 horizon and at

the regional or national level. The key for such future work, as was the case with the current electric sector allocation, will be to identify data sources that are not subject to manipulation.

Allocation to Electricity Utilities

I-19. Comment: The renewable energy program and GHG reduction program complement each other in that they both will reduce GHG emissions. And, both could place a substantial financial burden on ratepayers. A GHG Program that would require utilities to purchase GHG allowances while at the same time the utilities are committing substantial resources to procure renewable energy will take its toll on the financial stability of the utilities. The reality is that the ratepayer will pay for the utilities efforts to reduce GHG. To also pay for the allowances would be asking the ratepayer to pay twice and not be assured that they would see the financial benefits returned in their electric bills. We believe that the distribution of the allowances will be critical to the success of the program. There have been several proposals that very well could shift the compliance burden from one utility to another (or one region of California to another). For example, this could happen by using data from programs such as conservation, energy efficiency and renewable energy. Then, using this information to estimate the GHG reductions that were accomplished, and then using this information as the bases to provide additional allowances to a utility. These extra allowances would then be removed from another utility to maintain the established allowance cap. The utility with the reduced allowance would be placed at a disadvantage in achieving compliance with the Program goals. If ARB is considering this method, then we recommend that ARB increase the initial sector allocation to allow for the adjustments with a goal that no electric utility will have a short fall and receive less than its original allocation. However, any program that has to rely on estimates or projections for crediting GHG emission reductions is suspect. Therefore, we recommend and support a program that utilizes a utility's GHG emissions, as reported to ARB, as the bases for determining the allocation of allowances. The resultant allocation program would be fair, straight forward, understandable and provide regulatory certainty. (WPA)

Response: We are committed to reducing the burden of these programs on the ratepayer. We modified the regulation to include 95892, to ensure that allowance value distributed to utilities is used to benefit the ratepayer. Additionally, we developed an electric utility allocation methodology based on cost burden, energy efficiency, and early action that we believe is equitable. We disagree that ratepayers will pay twice due to the renewable energy program and cap-and-trade program because investment in renewable energy will reduce the utilities' compliance burden.

Support

I-20. Comment: We think your guiding principles have been maintained, and we support specifically the administrative allocation of the allowance to the electric sector, the benefit of consumers, in particular support of the proposal of approximately 97.7

MMT. We support the policy guidance that the resolution gives the staff and how to allocate the allowances among the utilities. We support giving the staff authority to deal with the remaining implementation details. And Californians at this point I think can be just as proud of the continuing leadership in the greenhouse reduction measures. We will continue to support and implement the complementary measures in AB 32, energy efficiency and renewables so they will go a long way to ensuring our compliance. We will implement whatever procedures you adopt. However, we must ensure we maintain good custodians of rate payer dollars and keep rate increases to a minimum. (SCPPA4)

Response: Thank you for your support.

I-21. Comment: LADWP strongly supports policies that have been incorporated into the proposed regulation intended to help contain compliance costs, including administrative allocation of allowances to electric distribution utilities on behalf of their retail customers. (LADWP1)

Response: Thank you for your support.

I-22. Comment: DRA supports ARB's proposal to allocate allowances to the electric distribution utilities for the benefit of their customers. Free allocation of allowances to the electricity sector is essential for the California cap and trade program. This should provide the utilities with more time to reduce their emissions in a cost-effective manner, limit unnecessary short-term costs, and enable the utilities to transition to a low-carbon economy at the right pace. While it is clear that California can be a model for regional, national and international cap and trade programs, California consumers should not pay for the greater part of these efforts. (DRA)

Response: We agree. Thank you for your support.

I-23. Comment: We're supportive of the 97.7 million metric tons as an allocation to the electricity sector. It's that number set forth in Appendix 1 of the resolution. (NCPA2)

Response: Thank you for your support.

I-24. Comment: We're also pleased that the resolution addresses the need to further review allocation issues that may arise from electrification of the transportation sector. (NCPA2)

Response: Thank you for your support.

I-25. Comment: On the appropriate allocation of allowances to the electrical distribution utilities, NCPA believes that the distribution utilities are the best situated to deliver allowance values directly to retail customers throughout the state. (NCPA2)

Response: We agree.

I-26. Comment: NCPA supports the proposed regulation's free allocation of allowances to Electrical Distribution Utilities. Electrical Distribution Utilities are best situated to deliver the benefits of any allowance value directly to the State's retail customers and meet the stated objective of free allocation; that is "to ensure that electricity ratepayers do not experience sudden increases in their electricity bills associated with the cap and trade regulation" (ISOR, p. II-28). NCPA has long supported an allowance allocation methodology that recognizes electric utility investments in zero- and low-GHG emitting resources, including wind, solar, and hydro-electric, as well as investments in state-of-the art natural gas-fired electric generation facilities that emit far fewer harmful GHG emissions than their predecessor facilities. NCPA believes that any allowance allocation mechanism must recognize these investments, and should also create a program design that moves the entire state away from higher emitting resources. Clearly the move towards higher and higher renewable energy mandate one such tool, but others must also be employed. (NCPA1)

Response: We agree. Thank you for your support.

I-27. Comment: NCPA continues to work with the other members of the Joint Utility Group, as well as representatives from the California Environmental Protection Agency (Cal EPA) and CARB staff and other stakeholders in the interest of developing an allowance allocation compromise that can meet the objectives of the State's environmental and economic goals. NCPA generally supports the direction of the allocation compromise that has been discussed with the utility stakeholders and Cal EPA during the last six weeks. This compromise is based on three important principles:

(1) Covering each Electrical Distribution Utilities' cost burden associated with the Cap and Trade program,
(2) Recognizing Electrical Distribution Utilities' early actions and investments in renewable electricity generation, and
(3) Recognizing the cumulative energy efficiency reductions of each Electrical Distribution Utilities'.

NCPA believes that it is appropriate for an allocation method that includes these three factors to provide lower-emitting utilities with more free allowances at the start of the program, as this demonstrates that it is possible for an allocation method to cover a utilities' cap and trade related costs, as well as acknowledge the early investments in low-GHG emitting resources. The final consensus position that clearly meets each of the three discussed criteria must do so while still maintaining a total minimum allowance carve-out for the electric sector of 97.7 MMT (89 MMT referenced in section 95870(c)(1), plus an additional 8.7 MMT for CHP), and allocate those allowances freely to the Electrical Distribution Utilities as currently contemplated in the Proposed Regulation, including the right of the Electrical Distribution Utilities to retain the ability to utilize the value of the allowances for the benefit of retail ratepayers consistent with the goals of AB 32, and as directed by their governing bodies (local governing boards for the POUs or the California Public Utilities Commission for IOU). (NCPA1)

Response: We agree. Thank you for your support.

I-28. Comment: The Utilities strongly support CARB's decision to allocate free allowances to the electrical distribution utilities. The electrical distribution utilities are in the best position to assist California's ratepayers with the cost burdens associated with the Cap and trade program. The Utilities recommend the following changes to section 95870:

(c)(1) Electrical Distribution Utilities. The Executive Officer will place an annual individual allocation in the limited use *holding account of each eligible distribution utility on or before January 15 if each calendar year from 2012-2020 pursuant to Section 95892. Allowances available for allocation to electrical distribution utilities shall be 89 million multiplies by the cap adjustment factor in Table 9.2 for each budget year 2012-2020.* (MID1)

Response: Thank you for your support. We do not believe the modification you suggested is necessary, as the allocation mechanism is now specified in the regulation.

I-29. Comment: The Utilities support the intra-utility allocation recommendation developed by the JUG and CARB. The Utilities believe this recommendation adequately accounts for the cost burden of each electrical distribution utility, incorporates an appropriate amount of energy efficiency as well as early action. The Utilities believe it is important to have a set allowance allocation methodology in place and active prior to the start of the Cap and trade program as this will assist with the Utilities' long-term planning and budgeting in order to make the clean investments necessary to achieve the AB 32 reduction strategies. The intra-utility allowance allocation recommendation brought forward by CARB is a compromise that the Utilities are supporting because of the fairness and balance it creates for all the electric distribution utilities in California. The recommendation appropriately recognizes the cost burden that will incur on every electric ratepayer from the entire AB 32 program while effectively rewarding early action toward renewable energy and energy efficiency investments. The Utilities appreciate all of the work CARB has done to develop this recommendation and looking forward to working with staff over the next year on refinement of the data. (MID1, MID2)

Response: We agree. Thank you for your support.

I-30. Comment: The Utilities support the provision that will provide publicly owned utilities (POU) with the flexibility of either consigning their freely allocated allowances for sale at general auctions or applying them directly to meet cap and trade compliance obligations. As electric distribution utilities are diverse, this provision provides an important recognition in that covered entities should have a reasonable means to comply with the Cap and trade program in a manner that accommodates their respective business models and compliance strategies. The Utilities agree with CARB's rationale for this provision in that POUs are largely vertically integrated, and in addition points out that some POUs may be disproportionately impacted if required to participate in quarterly auctions due to significant capital needed, and the transaction costs expected to participate. (MID1)

Response: We agree. Thank you for your support.

I-31. Comment: REU is a member of the joint utility group and is supportive of the electric utility allowance allocation method that was presented here today. We believe this method is a fair and balanced approach that appropriately recognizes the cost burden that electric distribution utilities pass on to the residents of California. Even though REU's resource portfolio is 63 percent carbon free, a few years ago, we anticipated that this Cap and Trade Program could increase REU's electric rates by as much as 21 percent. So I'm very pleased to be standing here today supporting an allowance allocation methodology that will not create an immediate rate impact to REU customers. (RELECTRIC)

Response: We agree. Thank you for your support.

I-32. Comment: Section 95892(b)(2) allows publicly owned utilities to make an annual designation to place their freely allocated allowances either into their Limited Use Holding Account or into their Compliance Account. NCPA supports this provision as a sound means by which to avoid needless transactions. As noted in the ISOR, this distinction is warranted due to the fact that "most POUs own and operate their own generation and do not compete with independent generators in the way IOUs do." (ISOR, p. II-32) Because of this, allowances directly allocated to POUs may either be consigned for sale at the general quarterly auctions or used directly to meet their compliance obligations. If a POU decides to auction some of its allowances at the general auction, the same auction rules apply to the POUs as those described above for the IOUs. While there may be some concerns that this "option" limits the amount of revenue that a POU has to spend "exclusively for the benefit of retail ratepayers… consistent with the goals of AB 32," as mandated by section 95892(d)(3) for the use of auction proceeds, this concern is unfounded. Like all electric utilities, POUs are required to meet any number of programmatic measures under the Scoping Plan. The fact that a POU may not have to purchase allowances in the market and receive the corresponding revenue does nothing to change the total amount of revenue available to the POU for AB 32 related programs since the POU would most likely be both the original allowance seller and the most likely purchaser. As a practical matter, revenues not used to purchase allowances in the auction will be freed up for other AB 32 related expenditures, including savings from needless transactions costs, to be used for the benefit of the POU's retail customers consistent with the goals of AB 32. (NCPA1)

Response: We agree. Thank you for your support.

I-33. Comment: We commend CARB for adopting a cautious approach to the use of auctions in the early years of the program. We are keenly aware of the current political environment surrounding greenhouse gas legislation and "cap and tax" branding in particular in the United States, and thus believe CARB has been extremely wise in its decision to distribute allowances largely through direct allocation in the early years. This will help deflate political criticism of cap and trade as a tax: cap and trade systems do not inherently have to become implicit carbon taxes on end-use consumers if direct allocation is combined with regulatory control over consumer pricing in the utility sector.

A well designed and strictly enforced cap and trade system with direct allocation to power distributors and regulated consumer pricing by a watchful public utilities commission will largely contain the carbon price signal within the wholesale and generation market. This will have the desired effect of shifting the merit order away from the most fossil intensive sources of generation, while restraining the impact on end-use customers. This does require a disciplined and watchful utilities regulator, which California has, although we grant that this is not a universal truth in other parts of the country or the world. We note that most of the concerns about windfall profits resulting from free allocation to large emitters as witnessed e.g. in Germany and other nations under the European Union Emissions Trading Scheme (EU ETS) will not likely be replicated in California given the regulatory structure here, as generators and utilities will not be able to freely pass on the carbon price to consumers in the State. The price signal needed to affect consumer behavioral shifts to reducing energy consumption will admittedly be damped in this structure, but we note that California has a long and successful history in achieving the objectives around energy efficiency and demand side management through other regulatory tools including efficiency standards and utility incentive schemes.

We thus strongly endorse CARB's prudent allocation policy and hope that it helps defeat the cap-and-tax political argument at the federal level. We are confident that California's cap and trade system if designed and implemented correctly will demonstrate that carbon can be priced meaningfully and in a manner which places any cost burden predominantly on the fossil generation sources as opposed to the consumers. (CLIMATEWEDGE)

Response: Thank you for your support.

I-34. Comment: Under the allocation to electrical distribution utilities for protection of electricity ratepayers, section 95892(b)(2), POUs are allowed, after informing the Executive Officer, to divide their share of freely allocated allowances into portions designated for either:
(A) The publicly owned electric utility’s compliance account, or
(B) The publicly owned electric utility’s limited use holding account.
By including this provision, ARB has correctly acknowledged that the electric sector remains only partially deregulated and as a result the electric distribution utilities remain very diverse. This provision is an important recognition by ARB that all entities should have a reasonable means to comply with the cap and trade rule in a manner that accommodates their respective business models and compliance strategies. CMUA agrees with the rationale for the provision that POUs are largely vertically integrated,

and in addition points out that some POUs may be disproportionately impacted if required to participate in quarterly auctions due to significant capital needed, and transaction costs expected to participate. (CMUA1)

Comment: We agree with the baseline allocation of allowances for the electricity sector, and support the regulation, as it reflects the expected cost burden to distribution utilities, incorporates the expected benefits of energy efficiency investments, and recognizes early action. It also recognizes that there are very large emission reductions that are coming from direct regulations in the electricity sector. (CMUA2)

Response: We agree. Thank you for your support.

Water

I-35. (multiple comments)
Comment: Allocation of free allowances should be made to Metropolitan, analogous to the allocation that will be provided to the electric POUs and IOUs, if CARB determines that Metropolitan is to be included in the cap. Free allocation solely to electric utilities with retail customers and to specific manufacturing facilities is inequitable, unfair, and penalizes Metropolitan who buys energy at wholesale and consumes it for its own use for critical water deliveries into southern California. (MWDSC1, MWDSC2)

Comment: There is no rational justification for treating DWR as an independent, for-profit wholesale power producer. DWR owns no power plants; DWR only enters into wholesale power sales when its load unexpectedly drops, resulting in surplus power. All DWR power transactions are dedicated to acquiring energy necessary to make water deliveries. DWR does not compete with independent power producers for customers because it dedicates all the power it generates to move water, and acquires more power as needed. The SWP is a net buyer of power; its operations result in net pumpload demand for energy that must be procured in the electricity market. Indeed, having issued tax-exempt revenue bonds, DWR is prohibited from undertaking profit-making activities which would jeopardize the tax-exempt status of its bonds. It would be equitable to treat DWR the same way POUs are treated. Like a POU, DWR is a governmental entity providing a public service. All revenues are required to go to costs associated with providing that service. Many POUs engage in activities identical to DWR: they have hydropower generation, make market purchases of energy, use power to pump water, and deliver water to water users. While DWR provides no retail service of either water or electricity, this distinction does not justify disparate treatment. DWR understands that one component of the cap and trade regulation is the mitigation of economic impact on electricity consumers, and the granting of free allowances to IOUs and POUs is an effort to achieve that mitigation. However, DWR's ratepayers are also entitled to mitigation of the economic impacts of this regulation. As a wholesale water deliverer, DWR lacks the flexibility other electricity users might have to modify its practices. As noted above, DWR's priority is water deliveries and carbon price mitigation is subordinate to those water deliveries. In addition, the trail of costs from DWR's incurred expenses to the ultimate water user is so tangled and time-delayed that it cannot be assumed that a water user will recognize a power price signal and react by consuming less water, and that lower water consumption would consequently reduce GHG. Without proof of that connection, imposing a surrender obligation on DWR does not reasonably lead to an expectation that AB 32 goals will be achieved. The obligation is merely a financial penalty. The money that would be spent on allowances to meet the surrender obligation could be better spent on achieving the Department's GHG reduction goals already underway. If DWR is not excluded from the regulation, it should receive free allowances. AB 32 mandates that entities that have voluntarily reduced their greenhouse gas emissions receive appropriate credit for early voluntary reductions. DWR is voluntarily terminating its contract for energy from the Reid Gardner power plant in Nevada. The Climate Action Team cited this as a discrete early action (see "Climate Action Team Proposed Early Actions to Mitigate Climate Change in California, at page 6), and that was referenced in the Air Resources Board's report on early actions. AB 32 requires that DWR be awarded some form of credit for this early action. An appropriate credit would be a grant of free allowances to permit DWR to meet its surrender obligation for the remainder of the contract's term, to July of 2013. This would be a sensible, cost-neutral remedy which would protect DWR's reasonable expectations of credit and mitigate in part the financial impact DWR will suffer due to early termination action and alternative procurement. The proposed amendment to the regulation, above, would be an appropriate method to recognize the early action credit for DWR. DWR is open to discussing other forms of appropriate credit if the Board feels another methodology merits consideration. Modify section 95890(c) and 95892(f) as follows:

> <u>(c) Eligibility Requirements for the Department of Water Resources. Pursuant to Section 95892(f), the Department of Water Resources shall be eligible for direct allocation of allowances if it has complied with the requirements of the MRR and has obtained a positive or qualified positive verification statement for the prior year pursuant to the MRR.</u>
>
> <u>(f) On January 1 of each year during the first compliance period, the Executive Officer shall deposit in the Department of Water Resources' compliance account allowances in an amount equal to DWR's $MTCO_2e$ emissions reported pursuant to the MRR in the preceding year.</u> (DWR)

Comment: Like Metropolitan, the electric distribution utilities (EDU) buy wholesale energy to serve load. The major difference is that these utilities serve electric customers at retail while Metropolitan consumes the energy it purchases, and passes the costs along to its member agencies, the downstream water customers. In order to address costs, CARB is providing free allowances to utilities that buy energy at wholesale and have a retail customer base. This penalizes utilities that buy energy at wholesale and consume it. These utilities then must pass the cost on to downstream customers. (MWDSC1)

Comment: It is inequitable, ineffective, duplicative, and improper to burden water ratepayers with additional costs and pass the resulting revenues on to electric ratepayers DWR uses electricity to produce a "product," water, much the same as a manufacturer uses electricity. Like a manufacturer, DWR will pay a higher price for market energy once this regulation is in place. Similar to a manufacturer whose product reflects the higher price of electricity, DWR will pass those costs on, first to water contractors who will then pass the costs on to the end users of water. There is no justification for imposing an additional cost on DWR through a separate compliance obligation which DWR will necessarily pass on to its water contractors, and ultimately to the consumers of water. No such surcharge will be imposed on the end user of manufactured products. The regulation and accompanying ISOR contain no justification for this duplicative cost and disparate treatment. No AB 32 goals are furthered by making this distinction. The consequence of imposing a surrender obligation on DWR will be to transfer funds from water ratepayers to electricity ratepayers. DWR will need to purchase allowances, and the vast amount of allowances available at auction will belong to IOUs or POUs. The IOUs and POUs are required to utilize the auction proceeds for the benefit of their ratepayers. The regulation and accompanying ISOR contain no justification for this transfer. DWR is implementing ambitious programs to achieve a 20 percent reduction in water use by 2020. The additional expense of this market mechanism incurred by water ratepayers will reduce funds available for important water conservation efforts. (DWR)

Comment: DWR plays a unique role in California as a state agency that generates and purchases power at a wholesale level. It does not make retail sales, and is not an independent private power producer an investor-owned utility, or a local publicly owned utility. The focus of the ARB's regulatory efforts, naturally, has been on the primary players in California's energy market. Attempts to place DWR in a category with other entities are misguided. DWR deserves to be considered accurately, and in its proper role. Viewing AB 32 in light of DWR's status as a state agency, it is clear that no regulatory authority over DWR was contemplated under Parts 4 and 5 of AB 32. Indeed, AB 32 frequently calls out the special roles of state agencies in greenhouse gas reduction efforts, and AB 32 contains many references to state agency responsibilities and collaboration. Regulations promulgated under AB 32 need to reflect this distinctive role for state agencies such as DWR. Significantly, AB 32 prohibits the ARB from altering any programs administered by other state agencies for the reduction of greenhouse gas emissions: “Nothing in this part or Part 4 (commencing with section 38560) confers any authority on the state board to alter any programs administered by other state agencies for the reduction of greenhouse gas emissions” (section 38574). Excluding DWR from this regulation would be consistent with AB 32's directive to "consider the significance of the contribution of each source or category of sources to statewide emissions" (Health & Safety Code section 38562(b)(9)) and to "take into account the relative contribution of each source of GHG" (see section 38561). The emissions attributable to DWR's final 19 months of deliveries from Reid Gardner are not a significant contribution to statewide emissions, and no other DWR activity would make it a "covered entity" under the regulation. Modify section 95811 as follows:

(h) <u>This article does not apply to the California Department of Water Resources.</u>
(DWR)

Modify section 95802(a)(59) as follows:

(a)(59) "Electricity Importers" are marketers and retail providers that hold title to imported electricity. For electricity delivered between balancing authority areas, the entity that holds title to delivered electricity is identified on the NERC E-tag as the purchasing-selling entity (PSE) on the tag's physical path, with the point of receipt located outside the state of California, and the point of delivery located inside the state of California. Federal ~~and state~~ agencies are subject to the regulatory authority of ARB under this article, and include Western Area Power Administration (WAPA)~~,~~ and Bonneville Power Administration (BPA). ~~and California Department of Water Resources (DWR)~~ When PSEs are not subject to the regulation authority of ARB, including tribal nations and state agencies, the electricity importer is the immediate downstream purchaser or recipient, if any, that is subject to the regulatory authority of ARB. (DWR)

Comment: Metropolitan is a public water utility that purchases energy at wholesale and consumes that energy rather than reselling it. Entities covered in the Cap and Trade program are specific industrial facilities that directly emit greenhouse gases, and electric investor owned utilities (IOU) and electric publicly owned utilities (POU) with retail customers. The Cap and Trade program that CARB has laid out is not applicable to a public water utility such as Metropolitan. (MWDSC1)

Comment: DWR is considered a Covered Entity by virtue of its activities in the electricity sector. DWR is more comparable to an EDU than a generator or marketer, since the costs of the allowances it will be required to surrender will ultimately be passed to end-use consumers. Therefore, DWR should receive a direct allocation of allowances pursuant to regulations that are applicable to the electricity sector. Alternately, DWR should not be considered a Covered Entity under the regulations.

The Mandatory Reporting Regulations required DWR to report its GHG emissions according to the same rules that applied to retail electricity providers. Pursuant to a conversation with ARB GHG Inventory staff, the SWC understands that the emissions associated with DWR's imported electricity were included by ARB staff when the starting allowance budget level of 97.7 MMT was set. DWR will be responsible for incurring abatement costs tied to its emissions without the benefit of receiving that allowance value. The allowances to which DWR would otherwise be entitled will be distributed to EDUs who will not be responsible for any abatement costs associated with these emissions. Therefore, in order to ensure equitable treatment, DWR should be included in the list of Covered Entities that receive direct allowance allocations.

DWR will be required to pay the total allowance costs for its emissions if it does not receive a direct allocation of allowances. Under the proposed regulations, water wholesalers such as DWR are the only utilities whose downstream customers receive no relief from increased rates associated with AB 32 compliance. Water is an important commodity no less essential than electricity and water ratepayers cannot forego its consumption. ARB should be as mindful of the impacts on water ratepayers as they are of electricity ratepayers. Therefore, DWR should receive a direct allocation of allowances for the same purposes as EDUs, i.e., the protection of water customers.

DWR passes through all SWP power costs to the SWC agencies and, ultimately, to end-use water consumers. Thus, water ratepayers are in precisely the same situation as the retail electricity ratepayers as the incidence of the Cap and Trade program falls directly on them. Therefore, DWR should receive a direct allocation of allowances for the same reason that allowances are being given to EDUs.

In sum, if DWR does not receive free allowances for imported energy purchased to power the SWP, no other entity will be able to mitigate allowance-related costs to water consumers, defeating ARB's intent to protect end-use utility customers from exorbitant price increases. If ARB determines that providing free allowances directly to DWR is inconsistent with the requirements and goals of AB 32, it should work with the SWC to fashion a methodology to ensure that retail water utilities are treated in the same manner as retail electric utilities with respect to the mitigation of cost increases. Add section 95890(d) as follows:

Section 95890. General Provisions for Direct Allocations

(d) All provisions of this Article applicable to a publicly-owned Electric Distribution Utility shall be applicable to the California Department of Water Resources for the State Water Project pumping load reported under article 2, section 95111(e), title 17, Greenhouse Gas Emissions Data Report. (SWC1, SWC2)

Comment: The Sustainability Plan represents an AB 32-consistent emission reduction plan in which DWR can invest its allowance value, and DWR should receive free allowances on the same basis as a publicly-owned electric distribution utility. DWR's commitment to reducing GHG emissions is well-established by its current and prior actions. (SWC1)

> **Response:** We believe that it is important to capture the emissions associated with water distribution. There are opportunities for reductions in the emissions associated with this activity, and the emissions are not insignificant. The role of water distribution entities (DWR and MWD) in the economic value chain between producers of electricity and end-use consumers of water services is most closely associated with electricity marketers, and their treatment under the regulation is consistent. We believe that it would be inappropriate to provide direct allocations to the water distribution utilities for the benefit of end-use customers, because they do not have a direct relationship that would facilitate the return of value in a way that would maintain the marginal incentive of end-use customers to reduce emissions. Further, the emissions associated with water distribution are included in the share of value returned to end-use customers through the electric distribution utilities. We performed an analysis of the distortion created by returning value through electric distribution utilities, as opposed to water distribution utilities, and found the effect to be insignificant.

I-36. Comment: Metropolitan acknowledges that the definition of electricity importer covers both marketers and retail providers, and that the current proposed definition of marketers covers Metropolitan. However, Metropolitan is not a true marketer of electricity, as the term is typically used. Metropolitan only imports energy for the purpose of serving its own load on the CRA and not to "market" or resell this energy. Modify section 95802(a)(113) as follows:

> (113) "Marketer means a purchasing-selling entity that takes title to wholesale electricity <u>for the purpose of resale</u> and is not a retail provider."

This change would clarify that Metropolitan is not intended to be included in the Cap-and-Trade Program. However, this modification would not affect the inclusion of the other entities that CARB staff has identified for coverage under the regulation, nor would it impact the requirements that apply to these covered entities. (MWDSC1, MWDSC2)

> **Response:** We disagree. The definition is intended to capture all imported electricity delivered by entities other than retail providers, including the commenter.

Errors and Simple Section References

I-37. Comment: Section 95870(c)(1) (p. A-74) provides that allowances allocated to electrical distribution utilities are to be placed in the holding accounts of those entities. However, section 95892(b)(2) (p. A-74-75) provides that allowances to publicly owned electrical distribution utilities ("POUs") are to be placed in either limited use holding accounts or compliance accounts as designated by the utilities. Section 95870(c)(1) should be amended to refer to the option that will be available to POUs under section 95892(b)(2). (SCPPA1)

> **Response:** We made the suggested modification.

I-38. Comment: Section 95870(c)(1) provides that allowances allocated to electrical distribution utilities will start at 89 million. However, an additional amount of allowances will be allocated to utilities to reflect the utility share of cogeneration or "combined heat and power" ("CHP") emissions. The number of CHP-related allowances that are to be allocated to electrical distribution utilities should be specified in section 95870(c)(1). (SCPPA1)

> **Response:** We made the suggested modification.

I-39. Comment: Section 95890(b) (p. A-77) states that an electrical distribution utility will be eligible for a direct allocation of "California" in specified circumstances. Presumably the intended reference was to "California GHG Allowances." The missing words should be inserted. Section 95890(b) also refers to an entity's "positive or qualified positive verification statement on its sales number." The term "sales number" is not defined. This term should not be used because a verification statement relates primarily to emissions, and liability is not determined by reference to electricity sales. Modify section 95890(b) as follows:

> An electrical distribution utility shall be eligible for direct allocation of California <u>GHG Allowances</u> if it has complied with the requirements of the MRR and has obtained a positive or qualified positive verification statement ~~on its sales number~~ for the prior year pursuant to the MRR. (SCPPA1)

Response: We made the suggested modification.

I-40. Comment: The eligibility requirements for electric distribution utilities in subparagraph (b) reflects an omission of the word "allowances" and an error that incorrectly makes reference to a "positive or qualified positive verification statement on *its sales number* for the prior year pursuant to the MRR." LADWP recommends that this subparagraph be revised to read as follows:

"(b) Eligibility Requirements for Electrical Distribution Utilities. An electrical distribution utility shall be eligible for direct allocation of California <u>allowances</u> *if it has complied with the requirements of the MRR and has obtained a positive or qualified positive verification statement* ~~on its sales number~~ <u>of emissions</u> *for the prior year pursuant to the MRR*." (LADWP1)

Response: We made the suggested modification.

I-41. Comment: Correct subsection reference on page 85.

> (2) For investor owned electrical utilities receiving a direct allocation of allowances pursuant to 95892(b) and subject to the monetization requirement pursuant to 95892(c): the auction purchase limit in (A) does not apply. This subsection (B) shall not be interpreted to exempt said investor owned electrical utilities from any other requirements of this article; and... (CCEEB)

Response: We made the suggested modification.

I-42. Comment: Modify section 95890(b) as follows:

> "Eligibility Requirements for Electrical Distribution Utilities. An electrical distribution utility shall be eligible for direct allocation of California <u>GHG allowances</u> if it has complied with the requirements of the MRR and has obtained a positive or qualified positive verification statements on its sales number for the prior year pursuant to the MRR." (NCPA1)

Response: We made the suggested modification.

Electrical Cooperatives Allocation

I-43. (multiple comments)
Comment: CARB notes that “free allocation of allowances to public utilities on behalf of their customers is designed to help offset the cost impacts of AB 32 policies” (ISOR, p. IX-55). For purposes of this program, Electrical Cooperatives have many of the same characteristics as POUs and IOUs, and further meet the requirements of section 95802(a)(57) for providing “electricity to retail end users” in California. Similarly, Electrical Cooperatives will be impacted by many of the same AB 32 obligations associated with mandatory programs established to meet the policies set forth in AB 32, as well as compliance costs associated with the Program. Accordingly, it is appropriate for them to also be eligible for the receipt of free allowances on behalf of their customers.

CARB notes that “electrical distribution utilities provide electricity to residential and small commercial customers” and proposes to allocate free allowances to them “because electrical distribution utilities are best situated to utilize the value of allowances for ratepayer benefit” (ISOR, p. II-32). Because Electrical Cooperatives also provide these same services with many of the same responsibilities and obligations as POUs and IOUs, and are also similarly situated to maximize the value of the allowances to deliver benefits to their ratepayers, Electrical Cooperatives are properly included within this definition. (NCPA1, AEPC)

Comment: Because Arizona Electric Power Cooperative is a non-profit, 100 percent debt-financed, member owned entity, all its costs, including rate increases, flow directly to AEPCO's member-owners, who in turn pass it on to the ultimate consumer in the distribution cooperatives' service areas. AEPCO's member base is much smaller than investor owned utilities' customer bases; therefore, the rate increases that will inevitably result from the cost of compliance without receiving the allowances will be much greater for AEPCO's members than it will be to investor-owned utilities where the costs are balanced between the shareholders and customers. In the absence of allowances, the cost of compliance will go directly to AEPCO, which will be passed on to its ratepayers, which are the ultimate consumers of AEPCO's cooperative distribution entities, including Anza Electric Cooperative. (AEPC)

Comment: Electrical Cooperatives have all of the same characteristics as POUs and IOUs, and further meet the requirements of section 95802(a)(57) for providing "electricity to retail end users in California. Electrical Cooperatives will be impacted by many of the same AB 32 obligations associated with mandatory programs established to meet the policies set forth in AB 32, as well as compliance costs associated with the Program. Accordingly, it is appropriate for Electrical Utilities be eligible for the receipt of free allowances on behalf of their customers; and as a non-profit organization, Electrical Cooperatives should have the option to sell its allowances at auction or use them directly for meeting compliance obligations as the POUs do. (AEPC)

Comment: In the proposed regulation "Electrical distribution utility(ies)" means an Investor Owned Utility (IOU) as defined in the Public Utilities Code section and 218, or a local publicly owned electric utility (POU) as defined in Public Utilities Code section 224.3, that provides electricity to retail end users in California." This definition does not include a category of electric providers that are similarly situated to IOUs and POUs; Electrical Cooperatives. Electrical Cooperatives are defined in Public Utilities Code section 2776 as "any private corporation or association organized for the purposes of transmitting or distributing electricity exclusively to its stockholders or members at cost." As such, Electrical Cooperatives are a "hybrid" between a POU and IOU, in that they are owned by their members, but operate as a non-profit public service for end use members. Electrical Cooperatives in California are small utilities located in rural areas, facing high infrastructure costs and other obstacles as they strive to provide affordable and reliable electric service to their members. As non-profit, member-owned utilities governed by their locally-elected boards of directors, they must adhere to federal Rural Utility Service (RUS) guidelines, but are also subject to many of the same AB 32 mandates as IOUs and POUs.

NCPA recommends that the proposed regulation be revised to provide that Electrical Cooperatives be included in the definition of "Electrical distribution utility(ies)", and that those Electrical Cooperatives that serve retail customers be eligible to receive electric sector free allowances. Including this small group of utilities within the definition of "Electrical distribution utility(ies)" would not change the scope of the program, nor have an impact on the recent discussions regarding allocation of allowances to the electricity sector, and data from the Electrical Cooperatives should already be part of 89 million allowances available for allocation to electrical distribution utilities. (NCPA1)

Comment: In section 95892, the proposed regulation specifically addresses the need to allocate allowances to Electrical Distribution Utilities "for the protection of electricity ratepayers." Electrical Cooperatives have electricity ratepayers, the same as all other Electrical Distribution Companies. However, unlike energy service providers, electrical cooperatives provide more than just the electricity transaction to their customers, therefore making them analogous to IOUs and POUs for the purposes of the proposed regulation. If the definition of "Electrical distribution utility(ies)" is not changed as described above to include the Electrical Cooperatives, the ratepayers of these entities will bear the total cost of the cap-and-trade regulation. Accordingly, modify section 95802 (a)(57) as follows:
"Electrical distribution utility(ies)" means an Investor Owned Utility (IOU) as defined in the Public Utilities Code section and 218, or a local publicly owned electric utility (POU) as defined in Public Utilities Code section 224.3, <u>or an Electrical Cooperative as defined in Public Utilities Code section 2776</u>, that provides electricity to retail end users in California. (NCPA1)

Comment: In the proposed regulation, "Electrical distribution utility(ies)" means an Investor Owned Utility (IOU) as defined in the Public Utilities Code section 218, or a local publicly owned electric utility (POU) as defined in Public Utilities Code section 224.3, that provides electricity to retail end users in California." (section

95802(a)(57)). The title "California retail end users" is synonymous with "California ratepayers." The proposed definition incorrectly fails to include Electrical Cooperatives. Electrical Cooperatives are a category of electricity providers that are similarly situated to IOUs and POUs, in that Electrical Cooperatives also provide electricity to California ratepayers. The only difference is that in an electrical cooperative system, the ratepayers are the ultimate consumer of the electricity provided by the cooperative distribution entity (such as Anza), which distributes the electricity at cost to its rural service area. AEPCO recommends that the proposed regulation be revised to include Electrical Cooperatives in the definition of section 95802(a)(57) and like POUs and IOUs, be eligible to receive electric sector free allowances. (AEPC)

Comment: If the definition in section 95802(a)(57) is not changed to include the Electrical Cooperatives, the ratepayers of these entities will bear the total cost of the cap-and-trade regulation. Modify section 95802 (a)(57) as follows:
"Electrical distribution utility(ies)" means an Investor Owned Utility (IOU) as defined in the Public Utilities Code section 218; a local publicly owned electric utility (POU) as defined in Public Utilities Code section 224.3; <u>or an Electrical Cooperative as defined in Public Utilities Code section 2776</u> that provides electricity to retail end users in California. (AEPC)

> **Response:** We agree. We modified section 95892(b)(2) to make electrical cooperatives eligible for allowances, and we modified 95802 (a)(57) (now 95802 (a)(82)) as requested. Table 9-3 shows an allocation to Anza Electric Cooperative.

Other

I-44. Comment: Occidental Petroleum Corporation (Oxy) has four significant interests in California oil and gas extraction operations. Each operation purchases significant amounts of electricity from an investor-owned utility to support their operations. ARB proposes to provide free allowance allocations to energy-intensive trade-exposed (EITE) to *"avoid imparting undue initial economic gain or loss"* in the early program years and to prevent leakage. The method of determining how many free allowances must be provided to achieve this objective does not meet the agency's own objective of ensuring that trade-exposed entities receive coverage of the emissions costs associated with their electricity use. ARB should rectify this inconsistency to avoid competitive impact in one of two ways: (1) require the utility to share the benefits of free allowance value with trade-exposed entities through *direct rebates* or (2) provide to an EITE entity a direct allocation of free allowances for power purchased from a distribution utility and exclude that entity's usage from the allocation of free allowance value to its serving utility. (OOGC)

> **Response:** We modified section 95892 to ensure that allowance value distributed to utilities is used to benefit the ratepayers, including industrial customers. The CPUC and the POU governing boards will determine the most equal and fair way to redistribute the auction value back to its customers. ARB

will continue to work with the CPUC, POU governing boards, and other regulating entities as directed in Board Resolution 10-42 to ensure that the auction value distribution is fair, avoids emissions leakage, and follows the guidelines laid out in section 95892.

I-45. Comment: Two elements of the proposed program may not be obvious to the casual observer. First, the rebates will be made "per capita," meaning that each ratepayer will receive an equal share of the rebate. But the costs in higher rates will be paid disproportionately by larger users of electricity. The price of electricity will go up for large users (and the usage will presumably decline), while the price for small users will go down (and the usage will presumably increase). The program therefore redistributes the right to use electricity and redistributes the income earned on allowances from the larger (richer) users and allocates it to the smaller (less wealthy) users. If the usage of electricity is based on demand, and demand is based on price, it is entirely possible that the shift of rebates from larger users to smaller users will simply change usage patterns, and not change overall demand. (HOR)

Response: The CPUC and the POU governing boards will determine the most equitable way to redistribute the auction value back to its customers. ARB will continue to work with CPUC, POU governing boards, and other regulating entities as directed in Board Resolution 10-42 to ensure that the auction value distribution is both fair and follows the guidelines laid out in section 95892.

I-46. Comment: Add section 95892(c)(3) as follows:
<u>The electrical distribution utility shall set aside allowances for each calendar year in an amount sufficient to satisfy the compliance obligation of any covered entity attributable to generation of electricity purchased by the electrical distribution utility pursuant to a Pre-AB 32 Power Purchase Agreement, as defined in Subarticle 2. These allowances shall be set aside prior to each auction that the electrical distribution utility offers allowances for sale. If the verified emissions attributable to the Pre-AB 32 Power Purchase Agreements exceed the amount of allowances set aside by the electrical distribution utility, the electrical distribution utility shall obtain the remaining amount of allowances from the next quarterly auction, or through the Allowance Price Containment Reserve. The electrical distribution utility shall transfer the required amount of allowances to the covered entity from which it purchases electricity under the Pre-AB 32 Power Purchase Agreement no later than 30 days before the covered entity's annual and triennial compliance obligation.</u> (WEC)

Response: We disagree. We believe that these matters are best resolved through bilateral negotiations between the contracting parties, and that any intervention on our part would be inappropriate at this time.

I-47. Comment: The first issue is that [some] regulated parties that are required to obtain allowances do not receive allocations of them. These entities include independent electricity generation facilities and electricity importers. These regulated entities must purchase allowances at auction or directly from utilities. This method of allocation means that no entity other than a utility can be assured of being able to purchase allowances. In the absence of reasonable certainty regarding the cap, any entity with allowances will seek to hoard them until the regulatory environmental is clearer and the adequacy of the cap and allocation methods is determined. Without allowances, those entities cannot operate, so these are life-and-death issues. There is nothing in the program that ensures that allowances will be made available to non-utilities at reasonable prices. (HOR)

> **Response:** The consignment mechanism, quarterly auctions and reserve sales, and proposed purchasing limits guarantee that all compliance entities will have a regular opportunity to acquire allowances at auction.

I-48. Comment: This allocation method does not recognize the fundamental advantage enjoyed by utilities in the marketplace. Electric utilities can recover their expenses for buying allowances through increased rates approved by the California Public Utilities Commission. No other market participants have this power. Accordingly, in a head-to-head competition for allowances, the utilities necessarily win. They can bid whatever is required in order to obtain the allowances required to operate, and rates will be increased accordingly. (HOR)

> **Response**: We disagree and believe the system is set up to be fair and equitable. We allocate allowances to utilities on behalf of ratepayers and modified section 95892 to ensure that allowance value distributed to utilities is used to benefit the ratepayer.

I-49. Comment: Allowances will be distributed "for free" to all utilities, but IOUs then have to submit their allowances back to ARB for auction. Publicly-owned utilities (POU) do not have to submit their allowances for auction, but may keep them for their compliance purposes. The minimum auction price is \$10/CO_2e, and ARB expresses the view that a price of \$30/CO_2e is somehow reasonable or appropriate. Moreover, there is no ability for utilities to constrain demand. They cannot impose a direct price signal to consumers to reduce their consumption of electricity. The utilities are required by law to keep serving the demand, and there is no direct method of limiting that demand. The result is that electric utilities must obtain the allowances necessary for their operations, and can pass through the costs. All other regulated entities, whether they be industrial concerns, independent power generators or industrial generators of electricity, will be at a disadvantage to the regulated utilities in connection with obtaining allowances. (HOR)

> **Response**: We disagree that utilities cannot reduce demand. Energy-efficiency programs and tiered rate pricing are two mechanisms that utilities have successfully employed to reduce demand in California. A primary goal of the program is to create a price signal to reduce greenhouse gas emissions. The allocation mechanism requires that allowance value provided to utilities be used to benefit ratepayers; see section 95892(a). The cost of compliance also drives greenhouse gas reductions in other industries. In the case of energy-intensive,

trade-exposed industries that cannot pass along costs to consumers, potentially creating a risk of emissions leakage, free allocation is provided to mitigate this risk. We expect that generators will be able to pass along the cost of compliance to the utilities that purchase their electricity to serve retail load, and to industrial consumers that purchase directly. Because the majority of allowances provided to utilities will be consigned to auction, generators, be they utility or independently owned, will have equal opportunity to compete for allowances at quarterly auctions.

I-50. (multiple comments)
Comment: Section 95890(b) states that an electric distribution utility is only eligible for direct allocation of allowances if it has complied with the mandatory reporting regulations and obtained a positive or qualified positive verification statement on its sales number for the prior year. SMUD requests clarification of this provision, as it appears to be missing the word 'allowances' in the second sentence, and refers to verification of a utility's "sales number", which has an unclear relationship to the allowance allocation structure. This language may be a holdover from a draft of the regulations when the ARB was considering allocation utility sector allowances based on sales, but regardless of genesis, it should be clarified. SMUD does not believe, as implied by the text, that an electric utility's allowances should be wholly taken away in one year based on a previous year's verification issue, this is an onerous penalty for a verification misstep. However, if that is ARB's intent, some thought and language should eventually address what happens to the allowances that may be withheld, for whatever reason, from an electric utility or other obligated entity. (SMUD1)

Comment: In some instances, a covered entity may be in the process of correcting a verification issue up until the deadline for direct allocation disbursements (which is on or before January 15 of each calendar year). If such is the case, the Utilities propose that the said entity be allowed to petition the Executive Officer to receive their allotted allowance allocation, should the verification issue be resolved to a positive verification. We request modifying section 95890 as follows:

> *(b) Eligibility Requirements for Electrical Distribution Utilities. An electrical distribution utility shall be eligible for direct allocation of California* <u>allowances</u> *if it has complied with the requirements of the MRR and has obtained a positive or qualified positive verification statement on its sales number for the prior year pursuant to the MRR.* <u>An entity that has not obtained a positive or qualified positive verification pursuant to the MRR may petition the Executive Officer for a direct allocation of California allowances if the entity is in the process of correcting the verification issues.</u> (MID1, NCPA1)

Comment: In order to be eligible for free allocation of allowances, Electrical Distribution Utilities must have a positive or qualified positive verification statement based on their Mandatory Reporting Regulation obligations (section 95890(b)). NCPA supports the proposed revisions suggested by MID/REU/TID,7 that would allow an entity to petition for eligibility pending correction of a verification statement.
Modify section 95890(b) as follows:

(b) Eligibility Requirements for Electrical Distribution Utilities. An electrical distribution utility shall be eligible for direct allocation of California GHG Allowances if it has complied with the requirements of the MRR and has obtained a positive or qualified positive verification statement on its sales number for the prior year pursuant to the MRR. An entity that has not obtained a positive or qualified positive verification pursuant to the MRR may petition the Executive Officer for a direct allocation of California GHG Allowances if the entity is in the process of correcting the issues raised in the verification statement. (NCPA1)

Response: Thank you for the note. We made the typographical edit to incorporate the word "allowances." We did not include the language pertaining to the opportunity to petition the Executive Officer. We believe that it is important for the integrity of the program that any free allocation of allowances be withheld, to ensure that the entity provides a verified emissions statement and product data statement, where a product data statement is applicable.

Revenues Instead of Auction Rights

I-51. Comment: Simply assign the distribution utilities, at least the investor-owned ones, Auction Revenue Rights (ARRs) than go through the ritual of formally allocating the allowances to the utilities, then having them formally consign them back for auction. Similarly, we believe it would be better to assign ARRs to trade-exposed businesses, rather than actually give them allowances. (MSCG2)

Response: We disagree. We prefer to directly allocate allowances and have individual entities offer them at auction. This ensures similar treatment for IOUs, POUs, and industry.

Auction

I-52. (multiple comments)
Comment: Reconsider the allocation of allowances to utilities and the rebate of auctioned proceeds from other buyers of allowances back to utility rate based customers. This is a significant issue because utilities will be in a position to essentially bid up the price of allowances and rate base the proceeds or rate base the cost, and then rebate the proceeds of the auction back to their customers. That process of auction and rebate to the ratepayers does not make a lot of sense to me. Other participants who don't get allowances, industries and importers of electricity and independent power generators, will be bidding for those allowances as well, while the proceeds of those auctions will be going back to the rate payers. These cross industry subsidies have not been properly considered in the staff's review of the economic impacts. I think this is going to end up creating cross sectorial competition for allowances, which is a game that the utilities will be in a better position to play than anybody else. Regulated parties who are obligated to submit allowances to continue their operations should be allocated allowances from the state. (LAWRENCER)

Comment: The first issue I think needs to have a harder look taken at is the allocation of allowances to utilities and the rebate of auctioned proceeds from other buyers of allowances back to utility rate based customers. The reason I think this is a significant issue is that utilities will be in a position where they can essentially bid up the price of allowances and rate base the proceeds or rate base the cost and then will in the end be rebating the proceeds of the auction back to their customers. That process of auction and rebate to the rate payers does not make a lot of sense to me, but it's more difficult it seems to me because other participants who don't get allowances, industries and importers of electricity and independent power generators, will be bidding for those allowances as well. And the proceeds of those auctions will be going back to the rate payers. So you have cross industry subsidies which I think have not been properly considered in the staff's review of the economic impacts here. I think what this is going to end up creating is cross sectorial competition for allowances, which is a game that the utilities will be in a better position to play than anybody else. Regulated parties who are obligated to submit allowances to continue their operations should be allocated allowances from the rate. (LAWRENCER)

> **Response:** We do not agree that utilities will bid up the price of allowances. The IOUs were required to divest almost all fossil-fuel power plants and now purchase electricity from independent power plants that emit GHGs. If they bid up allowance prices, their costs for purchased power from fossil-fuel power plants will increase proportionally to the increase in auction settlement prices.
>
> We modified section 95892 to ensure that allowances allocated to utilities are used exclusively for the benefit of retail ratepayers. Retail ratepayers include essentially all households, and the vast majority of commercial and industrial electricity users. Although the revenue goes through the utilities, its use is subject to the limitations of their governing bodies (POUs) or the CPUC (IOUs). We have worked with, and continue to work with, the CPUC and POU governing bodies to ensure that all ratepayers, including industry and independent generators, benefit from allowance revenue to the extent that they face carbon costs. We believe that importers of electricity and independent power generators will pass carbon costs through to the utilities.
>
> Finally, we modified section 95920 to clarify holding limits that apply to all entities, including utilities. Section 95912(j) requires the auction administrator to determine that bids and bid quantities conform with the holding limits. The consignment mechanism, auction requirements, and holding limits together limit the utilities ability to manipulate the market.

I-53. Comment: The regulations should clarify that EITE entities receiving free allowances may place those allowances in the auction or retain them for future compliance. (EPUC)

> **Response:** Auction consignment at ARB auctions is only available for the utilities and for ARB to dispose of allowances. Consignment of allowances at

ARB auction is not available to EITE covered entities. We expect EITEs will need the allowances allocated to them to meet their compliance obligation. If they have surplus allowances, they can sell them on the secondary market. Nothing prevents an EITE from retaining allowances for future compliance or sale in the secondary auction, except that they may not exceed the holding limit.

I-54. Comment: It is imperative that the auction rules that place restrictions on the transfer of allowances and Holding Accounts not adversely impact the legitimate ownership interests of government entities such as NCPA and its members. Accordingly, freely allocated allowances designated to Electrical Distribution Utilities whose generation resources are owned as part of a JPA arrangement in which the Electrical Distribution Utility is a member should properly be designated to either the Electrical Distribution Utilities' Compliance Account, as currently authorized under section 95892(b)(2), or into a Compliance Account held by the JPA. (NCPA1)

Response: We modified section 95892(b)(2) to allow Electrical Distribution Utilities that are publicly owned electric utilities or electrical cooperatives to designate the placement of their allocated allowances, either to their own compliance account, or into the account of a JPA of which the utility is a member, and with which the utility has a power purchase agreement.

Compliance Account

I-55. Comment: NCPA believes that requiring the designation [of allowances to compliance accounts or a limited use holding account] with regard to the next year's allowances during the timeframe contemplated by the proposed regulation is problematic. The "90 days prior" deadline falls on or about October 1, a month prior to the true-up for submittal of compliance instruments for the Triennial Compliance Obligation (section 96856(f)). It also precludes entities from being able to utilize all of the gathered data from the previous year upon which to make a determination regarding the election. NCPA recommends that publicly owned utilities be required to make this election by no later than 30 days prior to the start of the allocation year (i.e., December 1). Modify section 95892(b)(2) as follows:
(b)(2): Publicly Owned Electric Utilities. By no later than December 1 of each year, ~~At least 90 days prior to receiving a direct allocation of allowances~~, publicly owned electric utilities will inform the Executive Officer of the share of their allowances for the following calendar year that is to be placed....
(A) In the publicly owned electric utility's compliance account or compliance account of a Joint Powers Agency in which the Electrical Distribution Utility is a member and with which it has a power purchase agreement, or (B) In the publicly owned electric utility's limited use holding account. (NCPA1)

Response: Although we made the modification requested in 95892(b)(2)(A), we did not make the other modifications requested by NCPA1. As long as entities keep accurate records, the earlier deadline should provide ample time for entities to make their elections.

I-56. Comment: Modify section 95831(a)(4) as follows:
(a)(4)(A) A covered entity or opt-in covered entity may transfer compliance instruments to its compliance account at any time, <u>or compliance account of a Joint Powers Agency in which the Electrical Distribution Utility is a member and with which it has a power purchase agreement.</u>
(a)(4)(B) <u>Except as noted in subsection (A) above, a</u> ~~A~~ compliance instrument transferred into a compliance account may not be removed by the covered entity. (NCPA1)

> **Response:** This change is not necessary, as the changes in 95892(b)(2) resolve the commenter's concern.

I-57. Comment: LADWP appreciates that ARB proposes an administrative allocation to electrical distribution utilities for the protection of electricity ratepayers that recognizes the different business models of the utilities. As a direct result of AB 1890, the investor owned utilities (IOU), for the most part, divested of their fossil generation assets, and today have an indirect compliance obligation that is based primarily on power purchased from other generators. On the other hand, publicly owned utilities follow a different business model in which they continue to remain mostly vertically integrated utilities owning the majority of their generation assets on behalf of their customers. As a result, POUs maintain a direct compliance obligation for the electricity that they directly generate to serve native load. This is a fundamental difference that makes it imperative that the ARB maintain a Cap and trade program that accommodates these different business models in a way that maintains the environmental integrity of the program, while giving the utilities the flexibility they need to continue to make the necessary emission reduction investments in renewables and energy efficiency that will help transform the electric sector to low- and non-emitting generation resources. There are circumstances in which allowances should be allowed to be transferred directly from a compliance account of one entity to the compliance account of another covered entity. These include the following:

1. Energy purchases to make up for emergency outages affecting owned generation (fire, earthquake, equipment failure);
2. Energy purchases to make up for planned outages affecting owned generation (maintenance, upgrades, repowering);
3. Energy purchases to make up for under-production from intermittent renewables (renewable energy project is not delivering projected output for native load); and
4. Energy received from a jointly owned facility for retail sales where allowances are held by the joint owners in their capacity as electric distribution utilities, and the operator of the facility may be a joint owner operating the facility on behalf of the owners overall.

LADWP recommends that ARB revise the regulation to allow for these direct transfers of allowances from one compliance account to another compliance account. (LADWP1)

> **Response:** We disagree. However, we believe that the modifications made to section 95892(b)(2) provides sufficient flexibility for utilities that are members of JPAs to cover their obligations.

Consignment Auction

I-58. (multiple comments)
Comment: The Proposed Rule is made more perplexing by the rebate to ratepayers of the revenues earned from sales of allowances. Under the proposed rule, IOUs will bid on allowances in order to be able to maintain generation levels at those required to serve the demand. IOUs will pay whatever is required to obtain the allowances, because they can recover the costs of allowances in their rates. Rates will be raised to cover the costs of allowances. Then, the proceeds of the allowances will be rebated to the customers of the IOUs. The auction of allowances therefore raises rates to pay for allowances and rebates the proceeds to the ratepayers. It should be apparent that this system, in the aggregate, is a loop in which the original payment of the costs of allowances ends up back in the hands of those who made the payment in the first place. This system is the economic equivalent of allocating the allowances for free, except that it involves significant additional administrative expense. (HOR)

Comment: Reconsider the allocation of allowances to utilities and the rebate of auctioned proceeds from other buyers of allowances back to utility rate based customers. This is a significant issue because utilities will be in a position to essentially bid up the price of allowances and rate base the proceeds or rate base the cost, and then rebate the proceeds of the auction back to their customers. That process of auction and rebate to the rate payers does not make a lot of sense to me. Other participants who don't get allowances, industries and importers of electricity and independent power generators, will be bidding for those allowances as well, while the proceeds of those auctions will be going back to the rate payers. These cross industry subsidies have not been properly considered in the staff's review of the economic impacts. I think his is going to end up creating cross sectorial competition for allowances, which is a game that the utilities will be in a better position to play than anybody else. Regulated parties who are obligated to submit allowances to continue their operations should be allocated allowances from the rate. (LAWRENCER)

> **Response:** While the guarantee of revenue to consigners does mitigate the accounting cost of bidding in the auction, it does not put the consigners at an economic advantage, or give them an incentive to bid more than they otherwise would. To understand this, note that if a consigner can make a direct emissions reduction at a cost lower than the auction-clearing price, it is in the consigner’s best economic interest to make the reduction, rather than purchasing the allowance.

Auction and Holding Account

I-59. Comment: Auction infrastructure and the cost of allowances, as described in the Cap and Trade Regulation, is overly complicated, administratively burdensome, and does not guarantee cost containment for allowances. If Metropolitan is covered under the Cap and trade Regulation, as a public entity, it should not have to compete against private sector companies or IOUs to purchase allowances annually or for each compliance cycle. (MWDSC1)

> **Response:** We disagree. All participants at auction will have equal access to allowances in order to comply with the program. The auction rules are intended to limit market power by any one entity through purchase limits for most entities. Auction rules require certain reporting requirements and a financial guarantee. These rules are no more burdensome than the energy markets with which the commenter is familiar. We developed the program to allow a reasonable amount of offsets to be used for compliance and have included an allowance reserve to help contain allowance prices that is only available to entities with a compliance obligation.

I-60. Comment: It is imperative that the auction rules that place restrictions on the transfer of allowances and Holding Accounts not adversely impact the legitimate ownership interests of government entities such as NCPA and its members. Accordingly, freely allocated allowances designated to Electrical Distribution Utilities whose generation resources are owned as part of a JPA arrangement in which the Electrical Distribution Utility is a member should properly be designated to either the Electrical Distribution Utilities' Compliance Account, as currently authorized under section 95892(b)(2), or into a Compliance Account held by the JPA. (NCPA1)

> **Response:** We modified section 95892(b)(2) to allow Electrical Distribution Utilities that are publicly owned electric utilities or electrical cooperatives to designate the placement of their allocated allowances, either to their own compliance account, or into the account of a JPA of which the utility is a member, and with which the utility has a power purchase agreement.

Compliance Account

I-61. Comment: Modify section 95831(a)(4) as follows:
(a)(4)(A) A covered entity or opt-in covered entity may transfer compliance instruments to its compliance account at any time, <u>or compliance account of a Joint Powers Agency in which the Electrical Distribution Utility is a member and with which it has a power purchase agreement.</u>
(a)(4)(B) <u>Except as noted in subsection (A) above, a</u> ~~A~~ compliance instrument transferred into a compliance account may not be removed by the covered entity. (NCPA1)

Response: This change is not necessary, as the changes in 95892(b)(2) resolve the commenter's concern.

Imported Electricity

General

I-62. Comment: Covering imports of electricity from out of state is essential to maintain competitiveness in California and again is another improvement on the EU system where imports from neighboring countries are not addressed giving rise to opposition in certain trade exposed Member States. (SANDBAGCC)

Response: We agree and appreciate the support.

I-63. Comment: The compliance obligation for first deliverers of electricity should not include electricity that is generated out-of-state and sold outside California. As currently drafted, it appears that the Cap and trade regulation may inadvertently place a compliance burden on electricity that is generated out-of-state that does not enter California. The regulation must clarify this issue to ensure that electricity that is generated outside of California by a California load serving entity that is not imported into California is not a California greenhouse gas emission. The legislation did not provide ARB jurisdiction under AB 32 to consider external generation not imported, and therefore not subject to emissions reporting under section 38530 of the mandatory reporting regulation. The language proposed in section 95111(g)(5) of the mandatory reporting regulation should be deleted to ensure that such electricity is not treated as having an emissions compliance burden under section 95852 of the Cap and trade regulation. (LADWP1)

Response: The regulation specifically identifies the compliance obligation for first deliverers, including those that import electricity. The revisions to the mandatory reporting regulation are part of a separate rulemaking. However, section 9511(g)(5) of the MRR has been deleted, which we believe should satisfy the commenter's concern.

I-64. Comment: Two-way border adjustment is needed to prevent leakage in the electricity sector. LADWP supports ARB's efforts to address emissions leakage, which negatively affects California's economy and erodes the environmental integrity of the cap and trade program. While the first deliverer approach addresses the competitive advantage of importers of power into California, an additional mechanism is needed to address the competitive disadvantage faced by exporters of power generated in California. The proposed Cap and trade regulation requires California power generators to acquire compliance instruments to cover their greenhouse gas emissions, whether that power is consumed within California or exported.

If the exporter is not the generator, the exporter will nonetheless be liable for the costs of the compliance instruments as the generator will incorporate the cost into the price of the power. To remain whole, the exporter would need to pass the cost of the compliance instruments through to the out-of-state buyer, putting California exporters at a competitive disadvantage compared to out-of-state generators that serve load in jurisdictions where there is no cap and trade program. This may lead to emissions leakage, as power that was formerly generated within California becomes uncompetitive and is replaced with power generated outside California.

From an operational standpoint, not reimbursing exporters for the compliance cost of California power could have a negative impact on reliability of the electrical grid, especially as utilities must comply with pending regulations being promulgated by the Federal Energy Regulatory Commission (FERC) to provide regulation services every fifteen minutes for interconnected intermittent renewable resources like wind and solar. This regulation service is critical with regard to overall reliability of the WECC-wide (Western Electricity Coordinating Council) grid. If one utility is getting less output than expected from an interconnected intermittent renewable resource like wind, then other utilities may be required to provide energy to help meet that load, regardless of whether that need is in California or somewhere else within the WECC region. If electricity generated in California is exported to support load elsewhere within the WECC, the exporting entity should receive credit for the compliance obligation associated with the California power. If not, the higher cost of California power would be a disincentive to exporting power when it is needed to support reliability of the grid and the regulation conflicts with the comprehensive regulatory structure established by FERC. (LADWP1)

Response: AB 32 includes in its definition of Statewide greenhouse gas emissions (section 38505(m)) all emissions of CO_2e within California and emissions associated with imported electricity. It requires ARB to set a cap on these emissions. This regulation is a critical part of meeting that cap. It would be contrary to the requirements and intent of AB 32 if California added GHG-emitting generation, or increased the operation of existing GHG-emitting generation, in order to export electricity.

While it is possible that California electricity exported will be less competitive than other electricity that might be sold from other jurisdictions during the same time periods, it is not clear from the data that this is the case. This would depend on the availability of other resources at times when California utilities are exporting electricity. Nonetheless, the requirements of AB 32 preclude ARB from creating a policy that would increase GHG emissions within the state, as would a payment of allowances to exporters of fossil electricity.

It is highly unlikely, and no evidence has been presented, that reliability would be threatened if exported California electricity was more expensive. First, if transmission paths were available, other cheaper electricity could conceivably take its place. More likely, electricity purchasers in other jurisdictions would continue to trade for or purchase electricity from clean California natural gas power plants whenever needed for electricity system reliability.

Requirements for Specified Sources of Electricity

I-65. Comment: The proposed regulation sets the default emission rate for unspecified power based on a methodology that imputes an emission rate for the "average" emissions of all units that contribute to the pool of energy derived from unspecified resources. IEP is concerned that this methodology will frustrate CARB's GHG emissions reductions goals regionally and will promote contract shuffling. When the emissions rate of imported power from a known resource exceeds the rate imputed to unspecified resources, the First Delivers of the imported power will have an incentive to shield the true emissions associated with their power deliveries behind the marginal emissions associated with unspecified power deliveries. However, this incentive will evaporate if the imputed emissions rate for unspecified power is based on a measure of the marginal emissions rate of the units comprising the subset of unspecified power resources, rather than the average. Thus, the emissions rate for unspecified power should be based either on the marginal emissions rate of the class of electric generators used to calculate the emissions rate of unspecified power at a point in time; or, assuming the marginal unit varies over time, then the average emissions rate for the highest emitting quartile of the class of electric generators used to calculate the emissions rate of unspecified power.

In addition to supporting the tracking and accounting of imported power more closely on a regional, WECC basis (e.g., through the auspices of the WREGIS), IEP also recommends that the Initial Statement of Reasons be modified as follows:

5. Calculating Compliance Requirements
   b. First Deliverers of Electricity
      ….For this type of electricity (Electricity generated outside of California and imported into the State from an unknown source), there is no threshold for the compliance obligation, because it is not possible to trace it back to the generator. Since ARB does not know the source of electricity, staff does not know the amount of GHG emissions to assign to it. Therefore, staff proposes to use a default emissions factor for unspecified power. Staff recommends the emissions factor be based on <u>a measure of the marginal</u> emissions associated with the available electricity generation that could be sold on the spot market and brought into California. The GHG emissions will be calculated by multiplying this emission factor by the MWh delivered. (IEPA)

Response: We do not agree that the methodology used to assess the emission rate for unspecified power will compromise our emission-reduction goals. This comment applies more to the MRR revisions and we note that the MRR Staff Report explained that the default emission factor for electricity from unspecified sources is calculated using the Final WCI Default Emission Factor Calculator created by CPUC staff, vetted through the WCI Electricity Team, and adopted by the WCI Partners. The default emission factor is equal to the average marginal emission factor for years 2006, 2007, and 2008. It is based on marginal facilities likely to be dispatched in the WECC. Marginal facilities are defined as facilities with capacity factors lower than 60 percent. Two percent transmission line losses are included. The default emission factor is not based on the average of WECC units. Regarding the potential for contract shuffling, we included a prohibition against resource shuffling (another term for contract shuffling) in section 95852(b)(1), and a definition of resource shuffling in section 95802(a)(251).

The commenter's intent is not clear. It appears that the commenter would like the default emission factor to be calculated based on the marginal emissions rate of the same set of units for which the average rate was calculated by ARB. However, the marginal rate of this set of units is likely to vary significantly by season and by hour of the day as load varies. The commenter seems to prefer that a distinct default emission be calculated for "each point in time." Because the marginal emission rate varies continuously, and it cannot be calculated for a time interval smaller than one hour, it is not feasible to require stakeholders to use a default emission factor for each point in time, or for each hour. Since it is infeasible to calculate a default emission factor for "each point in time," it appears that the commenter recommends, as second best, that ARB use the average emissions rate for the highest-emitting 25 percent of the group of generators used in our methodology. However, this approach would not account for seasons and hours when generators in the group with lower emissions than the highest emitting quartile are on the margin. The commenter has not provided sufficient analysis of which generators are on the margin during which hours of the year to convince us that IEPs suggested methodology is more accurate the methodology we used. Finally, the regulatory process does not include modifications to the initial Staff Report; instead, this final Statement of Reasons provides the rationale for the final regulation.

I-66. Comment: The proposed amendments to the MRR would set forth a procedure for calculating the default emission rate for unspecified power based on the average emissions rate derived using calculation tools developed by the Western Climate Initiative and announced by CARB along with the proposed MRR amendments. This default emissions rate will then be used to calculate the allowance compliance obligation for unspecified power under the Proposed Regulation's cap and trade program. Calpine is concerned that, by relying upon a low default emissions rate for unspecified power, the Proposed Regulation will have the effect of allowing first delivers to classify their higher emitting imports as unspecified power so that they will be treated more favorably, in comparison to lower-emitting specified sources of imported power and in-state generating sources. This would have a perverse consequence of encouraging increased dispatch of higher-emitting sources, to the detriment of both lower-emitting specified imports and in-state generating sources. To address this problem, Calpine recommends that the default emission rate for purposes of both the proposed amendments to the MRR and the proposed regulation should be set at 1,100 lbs (0.55 tons) CO_2e per MWh, which is equivalent to the State's Emissions

Performance Standard and therefore represents the emission rate of the higher heat-rate existing combined-cycle gas-fired power plants likely to determine market-clearing prices in California. (CALPINE1, CALPINE2)

> **Response:** We agree that the default emissions rate is lower than some high-emitting sources of imports, and that absent other measures, there could, in some cases, be an incentive to dispatch higher-emitting resources. However, a new definition of resource shuffling (section 95802(a)) and a prohibition against contract shuffling have been added in section 95852(b). In addition, the MRR requires reporting that will help to track situations in which first deliverers attempt to classify higher-emitting imports as unspecified. We believe that these changes address the commenter's concerns.

I-67. Comment: In our view, creating complex rules for identifying emissions from individual sources may very well exacerbate "contract shuffling", not prevent it. The proposed "specified/unspecified" system will not inhibit contract shuffling, and in light of the potential risk it poses of significant disruption to efficient markets and power system operations, we believe that the impacts upon implementation merit close scrutiny. If adverse impacts on liquidity, reliability or price are observed, then it may be appropriate to revisit the specified/unspecified system. (MSCG2)

> **Response:** We agree that the regulation sections that explain the requirements for claiming a specified source alone may not prevent contract shuffling, and we modified the regulation to add a prohibition against resource shuffling (another term for contract shuffling) in section 95852(b)(1) and a definition of resource shuffling in section 95802(a)(251).
>
> We have also worked very closely with the California Independent System Operator (CAISO), the operator of California's main electricity market, to design compliance requirements for the cap-and-trade program that will not impede a smooth-functioning electricity market. As the program is implemented, ARB and our market surveillance committee will monitor both the emissions-trading market and the power market, and recommend changes to our program as appropriate. We believe that changes to the requirements for first deliverers of electricity are not needed at this time.

I-68. Comment: The details of how "specified" versus "unspecified" is determined should be part of the proposed regulation. At a minimum, there should be a cross-reference in the Regulation Order that explains where to find the necessary administrative details in the MRR. It is not clear from the draft regulations what is required for a First Jurisdictional Deliverer to treat imported power as from a "specified" resource under the Regulation. (MSCG2)

> **Response:** We have made modifications to the regulation that should provide clarity on this issue. Section 95892((b)(2) has been added to provide details on what is required in order to make a claim that electricity is from a specified

source. This section contains a cross-reference to section 95111 of the MRR, which provides additional details on specified versus unspecified sources. Section 95802(264) and (279) provide definitions of a specified source and unspecified sources. All other electricity is unspecified.

I-69. Comment: Section 95812(d)(2), says that “The threshold for an electricity importer of specified or unspecified source of electricity is zero as of January 1, 2015.” We would appreciate clarification of the meaning of this section. Modify the section to make the intent clear. (MSCG2)

Response: We agree and modified sections 95812(d)(2) to clarify that as of January 1, 2015, the applicability threshold for electricity importers is zero metric tons of CO_2e per year for specified sources and zero MWhs per year for unspecified sources.

e-Tags

I-70. Comment: Fourth, there is a potential ambiguity with regard to whether certain transactions occur within or outside California, and thus constitute “imports” or “first deliveries” of power under the electricity importing rules. Specifically, there are trading hubs along the California border where the exact physical location is undefined or ambiguous. The most potentially problematic are “COB” and “NOB.” Others that may raise questions include Mead and Palo Verde. At some point, the ARB will need to decide if transactions at these various “hubs” are in fact taking place “in California” for purposes of reporting and compliance. When those decisions are made, they need to be made part of the Regulation Order so parties have a reference source. One simple way would be to create a listing of all such hubs and indicate their “in-state” status for reporting purposes. Alternatively, it may be decided to make this list part of the MRR instead. In either case, the existence of the list should be cross-referenced in the other document. (MSCG2)

Response: We disagree that there is ambiguity with regard to transactions at the trading hubs. We have worked closely with CAISO, which operates the CAISO market in which these hubs are part of the path of electricity delivered into California. The PSE or Scheduling Coordinator that delivers to these hubs is required to deliver the electricity to a “hub” or “node” or, more precisely, Point of Receipt, in California. If such delivery does not take place, no sale of electricity takes place. CAISO is aware that some entities have not been using NERC e-tags and other system tools in full compliance with its requirements and tariffs that apply to participants in CAISO markets. We continue to work with CAISO to ensure that electricity importers understand and conform to requirements.

I-71. Comment: When considering the 2020 emission limit of 427 million metric tons of carbon dioxide equivalent ($MMTCO_2E$) of greenhouse gases in conjunction with the Western Climate Initiative (WCI), will emissions leakage be considered? How will the ARB attempt to account for multiple sources of power generation within the Western

Interconnection? Specifically, BC Power, the government-owned utility in British Columbia, has been in power deficit for 10 of the past 11 years. It makes up that deficit by importing coal-fired power from Washington state and the province of Alberta. BC Power then sells California "green" hydropower after backfilling their grid deficit with coal power. Will ARB account for this form of electron laundering by looking at the full life cycle emissions of the sources of power imported into California? Has ARB considered the cost impact of electricity to California consumers if BC Power, or other providers of electricity, are forced to purchase emissions allowances to fully account for their electron laundering? (ASMMANDEVORE1)

Response: We have done extensive work to consider, and eliminate to the extent possible, emissions leakage and economic leakage. For example, Appendices L and M of the Staff Report both devote many pages to leakage in the context of electricity. Furthermore, in section 95852(b) we distinguish between specified and unspecified sources of imported electricity and have added a specific prohibition against resource shuffling to address the potential for leakage when out-of-state sources of electricity are allocated compliance obligations under the regulation.

We agree that BC Power imports coal-fired power to meet part of its load. Furthermore, BC Power has exported power from various hydroelectric resources for many years. The regulation is not designed to undo existing or historical arrangements in which power is traded between jurisdictions. Instead, the regulation is designed to achieve real GHG emissions reductions going forward. For example, if BC Power increases exports to California from hydropower and simultaneously imports more coal power in order to provide low-emission factor power to California, we would consider that a form of resource shuffling.

In addition, British Columbia is, along with California, a member of WCI. We expect British Columbia to adopt regulations that conform to WCI guidelines in order to participate in a cap-and-trade program along with California, which will also help to eliminate the potential for leakage in BC Power operations.

I-72. Comment: Some studies have suggested that hydropower, depending on where it is sited, can be a net negative for GHG emissions because it can drown carbon-impounding forests while the rotting plant matter releases large amounts of methane. Given this, will hydropower from BC Power have a higher imputed GHG load than hydropower from the Hoover Dam, which did not drown forests as it was built in a desert? (ASMMANDEVORE2)

Response: Currently neither ARB nor the WCI take a full lifecycle approach to the emissions from electricity generation. This means, for example, that the GHG emissions created during the extraction of natural gas and coal is not considered in the attributions of GHG emissions to power generated at natural gas or coal power plants. In similar fashion, the emissions associated with the construction of wind and hydroelectric generators or the production of photovoltaic panels is not included. Therefore, a hydropower resource in BC and electricity from the Hoover Dam would both avoid a compliance obligation if specified according to the requirements of the regulation. We note that as California and other jurisdictions intensify efforts to mitigate climate change through policies and programs, the need for a full lifecycle approach to electricity generation is reduced, since more direct emissions in that lifecycle would be covered in these programs.

Unclassified

I-73. Comment: Constellation Energy is in favor of the “border adjustments” on power purchased from out of state generators as an equitable means of preventing “leakage” in the power sector. CARB’s economic analysis used several different models that generated a large range in allowance costs, from $15 to $160 per ton, depending on the year and the effectiveness of the program. At $45 per ton CO_2E, coal plants with existing PPAs are likely to become uneconomic. In addition to allowances, CARB is requiring facilities to pay an annual GHG program fee, and some facilities over 100 MW will also have to perform an energy efficiency evaluation. Constellation Energy is concerned that California plants will become uneconomic in competition with plants in other states prior to regulation under a federal program. Constellation Energy is concerned that CARB is underestimating the potential for leakage with respect to the IPPs. (CONSTELLATIONENERGY)

Response: The point of the regulation is to put a price on GHG emissions that ultimately will result in lower GHG emissions. Long-term, we expect that coal plants to become uneconomic, partly in response to this regulation, unless they can produce electricity with much lower emissions per MWh. We do not believe leakage is likely to occur as high-emission California power plants are dispatched less frequently, because the electricity they generate could not be replaced by other high-emission electricity given the requirements of section 95852(b) as modified and the California emissions performance standard under Senate Bill 1368 (Perata, Chapter 598, Statutes of 2006).

I-74. Comment: Wellhead is concerned that the proposed regulations do not adequately account for some of the intricacies in how the CAISO administers the market. The proposed regulation and ISOR assume that generators selling power to the wholesale markets will be able to recoup GHG compliance costs by including such costs in their bid prices. In general, CAISO market participants receive compensation at a rate no less than the price bid into the applicable market. However, there are certain exceptions where payments from the CAISO for energy dispatched by the CAISO do not include any consideration of GHG costs. This occurs when the CAISO dispatches a resource at minimum load or out of economic order (normally for reliability reasons). In these cases, the market rules assure the generator of receiving compensation that covers their cost of providing the generation dispatched by the CAISO. However, the current CAISO process does not include consideration of any GHG costs incurred by the generator in responding to these CAISO dispatch instructions. If the CAISO does not modify its market compensation process to account for a generator's actual GHG costs in these situations, the proposed regulations will create yet another class of generators without appropriate GHG cost recovery. (WEC)

> **Response:** We have worked closely with CAISO to develop requirements for first jurisdictional deliverers of electricity that dovetail with the existing electricity market structure. CAISO is working on how bids for electricity will incorporate GHG costs in the market. We will continue to work with CAISO to ensure that the sort of disadvantage to generators identified by the commenter does not occur.

Electricity: Renewable Energy

Renewable Electricity Credits (RECs)

I-75. (multiple comments)
Comment: Ensure equal treatment of all renewables that qualify for RES or RPS. The Mandatory Reporting Requirement rule raises an additional issue that is intimately related to the rules proposed under the Cap and Trade program. The proposed regulation should assign a zero GHG attribute to all renewable energy that meets RPS or RES requirements. In general, all renewable energy that meets State standards to qualify for the RPS or RES should be GHG-reducing to comply with California law and to maintain benefits that parties expected when complying with the RPS statute. The discussion points of this recommendation are detailed in our comments on the proposed amendments to the regulation for the Mandatory Reporting of Greenhouse Gas Emissions and are not discussed further in these comments. (SEMPRA1)

Comment: In order to ensure that the State's environmental objectives are consistently addressed, and to be consistent with the counting methodologies used in allowance allocation discussions, the proposed regulation must treat all renewable resources from existing California renewable energy programs as zero-emitting resources. Out-of-state renewable energy contracts that are currently valid renewable contracts for purposes of meeting the requirements of an existing renewable portfolio standard (RPS) program or are compliant with the recently adopted Renewable Electricity Standard (RES) regulation also contribute to the overall reduction of GHG emissions, and towards meeting the mandates of AB 32. Accordingly, they should be recognized as such in the context of the Cap and Trade Program, where appropriate. (NCPA1)

Comment: The compliance obligation for first deliverers of electricity under the Cap and trade regulation should be amended to account for emission reductions associated with the retirement of renewable energy certificates under the California Renewable Electricity Standard Regulation, page A-62 subparagraph (b). The draft regulation states that a deliverer of electricity covered under sections 95811(b) and 95812(b)(2) has a compliance obligation for "every metric ton of CO_2e emissions for which a positive verification statement or qualified positive verification statement is issued" and every metric ton of CO_2e of stationary source combustion emissions, or emissions associated with electricity imported into California from a source in a jurisdiction where a GHG emissions trading system has not been approved for linkage by the Board pursuant to Subarticle 12. The Cap and Trade regulation is not a stand-alone regulation; rather it is one piece of a larger program to achieve the state's emission reduction goal, and needs to dovetail with the other complementary emission reduction measures identified in the AB 32 Scoping Plan. As such, the Cap and trade regulation should recognize emission reductions achieved under other AB 32 regulations such as the Renewable Electricity Standard (RES). The RES environmental analysis suggests that increasing renewable energy from 20 percent to 33 percent will result in 11-12 MMT in GHG emission benefits ($MMTCO_2$e/yr) by 2020. The RES also acknowledges that emission benefits are "WECC-wide" insofar as compliance can be achieved through the purchase and retirement of renewable energy certificates (REC) generated within the WECC without actual delivery of the green energy to California.

This reduction in WECC-wide emissions due to the RES should be recognized under the Cap and trade regulation, and a first deliverer's compliance obligation under the cap and trade regulation should be adjusted to reflect the emission reduction associated with the RECs that entity has retired to comply with the RES. However, as currently drafted, the compliance obligation under the Cap and trade regulation will be calculated based on emissions reported and verified under the mandatory reporting regulation (MRR). Except to the extent that delivered renewable energy reduces emissions by displacing fossil generation, the MRR does not quantify emissions reduced as a result of purchasing and retiring unbundled RECs.

LADWP recommends that ARB fully acknowledge the WECC-wide emission reductions that will result from the RES. Without alignment between the RES, MRR, and Cap and trade regulations, entities will only be credited with renewable energy that is physically imported into California. Any RES compliance using unbundled RECs would result in a double-burden insofar as entities would pay the cost of purchasing the RECs as well as the cost of emission allowances for energy used to serve load in California. It would be inconsistent to count the emission reductions from the RES toward the AB 32 emission reduction target without also attributing those emission reduction benefits to the entities that are purchasing and retiring the RECs.

LADWP recommends the following be included in this section under section (b):

"First Deliverers of Electricity." A deliverer of electricity covered under sections 95811(b) and 95812(b)(2) has a compliance obligation for every metric ton of CO_2e emissions for which a positive verification statement or qualified positive verification statement is issued, and every metric ton of CO_2e of stationary combustion emissions, or emissions associated with electricity imported into California from a source in a jurisdiction where a GHG emissions trading system has not been approved for linkage by the Board pursuant to Subarticle 12. <u>This compliance obligation shall be adjusted for implementation of the Renewable Electricity Standard for the purchase and retirement</u>

of unbundled or tradable renewable energy certificates purchased and retired by the entity to comply with the Renewable Electricity Standard. (LADWP1)

Comment: PG&E requests clarification of the role of out-of-state renewable energy purchases in California's Cap and trade program. PG&E recommends ARB provide that resources eligible under the RES or RPS are credited as zero GHG to ensure that the RES, RPS, Cap and Trade, and Mandatory Reporting Regulations are consistent and achieve GHG reductions in the most cost effective manner. As such, the Mandatory Reporting Regulation should be revised to provide that imported Renewable Energy Credits (REC) include the renewable-GHG attribute of the out-of-state renewable facility from which it was generated. This approach ensures that California receives the full GHG reduction benefits of the State's renewable programs by providing consistency with the statutory and CPUC definitions of a REC and the numerous CPUC-approved RPS contracts that have been entered into on behalf of utility customers. (PGE1)

> **Response:** These commenters wish to use RECs to reduce their compliance obligation for electricity delivered to California in place of electricity from renewable resources that qualify under the RPS. They also request that all renewable energy that qualifies for the RPS be allowed to reduce their compliance obligation. We do not agree that RECs should reduce compliance obligation unless they meet the requirements that were in place for the RPS for investor-owned utilities prior to the passage of SBX1 2 (Simitian, 2011), and prior to the CPUC's decision to allow IOUs to use tradable RECs for RPS compliance.[6] Unlike the RPS, this regulation puts a compliance obligation on electricity delivered to California based on GHG emissions that occur in the generation of electricity. If the electricity delivered to California was generated in a facility that produces GHG emissions, and it was imported in place of electricity from a renewable resource, the regulation puts a compliance obligation on the electricity based on its actual emissions. However, we agreed with commenters that RPS electricity should reduce the compliance obligation of a first deliverer under the conditions laid out in new section 95852(b)(4).
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> In this response, we first discuss the modification we made to the regulation, then discuss concepts pertinent to the comments and our treatment of imported RPS eligible electricity. Finally, we respond to some specific points to further illustrate our approach.
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> As described more fully in our responses to the first 15-day changes to the regulation, we modified section 95852(b) to allow for an "RPS adjustment." With this approach, a first deliverer's compliance obligation may be reduced by the product of the default emission factor multiplied by the quantity of eligible

[6] Although the CPUC released the Decision in March 2010, it was stayed due to petitions for modification, so the IOUs could not use tradable *renewable* energy credits (TRECs) to comply with the RPS until the CPUC lifted the stay on January 13, 2011.

renewable electricity purchased by the electricity importer, or imported to California on behalf of an entity that owns or has contract rights to the eligible renewable electricity. With this approach, a compliance obligation may be reduced whether or not the RECs are “bundled” with the electricity or sold separately. This approach is consistent with our overall approach to require reporting and compliance obligation based on actual emissions from imported electricity that is delivered in real time to serve California load.

We note that under the RPS currently in effect, POUs, unlike IOUs, are allowed to choose certain options in their own RPS programs that are not available to IOUs. Of relevance here is that some POUs may have purchased “tradable” or “unbundled” RECs to count within their own programs, prior to the CPUC’s recent decision. We do not allow tradable RECs to be used in the calculation of any electricity importer’s RPS adjustment, unless the electricity that resulted in the creation of the RECs meets the requirements of new section 95852(b)(4).

Were we to recognize all RECs and RPS energy as “negating” the emissions from other electricity delivered to replace renewable generation, there would be significant opportunities for leakage. Allowing RECs to be used to help meet a compliance obligation would likely facilitate “double-counting” of an “avoided emissions” attribute, and would be incompatible with the WCI partners’ approach to renewable electricity.

A California cap-and-trade program that imposes a compliance requirement to obtain and submit allowances to emit greenhouse gases is fundamentally different than the compliance requirements for an RPS or RES program, which requires utilities to obtain a set percentage of their electricity sales from renewable resources. This regulation uses a metric of CO_2e emissions, while the RPS uses MWhs of electricity generated from renewable resources. Since these comments were submitted in December, 2010, the RES program has been discontinued, and the proposed regulation is no longer being considered by ARB. Instead, SBX1 2 was passed and signed, implementing a California 33 percent RPS requirement, obviating the need for RES. The proceedings to develop and implement the requirements of this bill are currently ongoing and will continue beyond the date of the finalized cap-and-trade regulation.

We note that tradable RECs that are eligible for use in the RPS program need not be associated with the actual disposition or delivery of the electricity generated at a renewable facility. We believe that electricity delivered from a zero GHG-emitting renewable resource for use outside of California is in fact electricity without GHG emissions, even if a REC associated with that electricity has been sold for use in the California RPS. Therefore, if a REC issued for a single MWh is used to reduce the compliance obligation of another MWh of GHG-emitting electricity imported to California, there would be two MWh of electricity with zero actual or deemed emissions, a form of double-counting.

Notwithstanding the analysis above, we added section 95852(b)(4), which should allow most electricity generated outside of California at eligible renewable energy resources to reduce an entity's compliance obligation. We also expect, that at least in some cases, entities that have purchased tradable RECs can enter into new contracts, or renegotiate contracts, to purchase electricity associated with the tradable RECs. This can make it possible to use the RECs and electricity together to reduce compliance obligation.

Before responding to additional specific points made in the comments above, we note that all of these comments were made prior to any regulatory language that considered a potential value for any renewable electricity that was not directly delivered to California. This means that the above comments generally are moot, and do not address the regulation. Nonetheless we respond here to certain comments.

First, despite NCPA1's contention, not all RPS electricity reduces GHG emissions. When hydroelectric power is abundant in the Northwest, sometimes there is an oversupply of electricity. Under such conditions, if a biomass facility that also uses natural gas but meets RPS requirements continues to generate, it will increase GHG emissions. To the extent that the biomass facility generates power, GHG emission-free hydroelectric would be replaced by generation with emissions.

With respect for PGE1's comment, we are not aware of any "renewable-GHG attribute" that has any regulatory meaning. As discussed in our responses to the 15-day changes to the regulation, the CPUC has made it clear that while RECs may have an "avoided emissions" attribute, the value of avoided emissions for some renewable electricity is zero.

I-76. Comment: The cap and trade program must harmonize with the renewable energy standard. SMUD understands that the WCI has recommended abandoning the renewable energy tracking system WREGIS for the purposes of tracking purchases of renewable energy under a First Jurisdictional Deliverer framework. SMUD, and other stakeholders in the electricity sector, have pushed back against this arbitrary decision given the harm that it does to the existing RECs market, to the harmony of the cap and trade program with the ARB's own Renewable Electricity Standard, to existing voluntary renewable energy programs, and to those responsible for tracking and reporting emissions at jurisdictions subject to the regulation. While SMUD is providing similar comments to the Mandatory Reporting regulation, we feel strongly enough about this issue that we raise it here again as an example of where the ARB could improve the harmonization of its cap and trade rule with the complementary policies. The decision made at the WCI was made with very little public process, and further adopted by ARB without a public workshop on the topic. Although the decision has been shared with a subset of utility stakeholders, there is little in the administrative record of this rulemaking, either in the ARB's record of workshops or in the background staff papers. As the ARB and CPUC seek to harmonize decisions around the use of RECs as a tracking mechanism for the RES, this issue will inevitably be brought into full public light. However, SMUD is concerned that the resolution of this issue may come only after the ARB reporting and cap and trade regulations have closed the door on this topic. (SMUD1)

Response: The commenter claims that WREGIS tracks renewable energy. The WREGIS system does not track electricity from generation to where it is consumed. The WREGIS system does not track electricity or emissions, but instead allows for the creation, registration, and tracking of RECs. There is no regional system for tracking the disposition of electricity, from renewable, fossil fuel, or any other kind of electricity generator. If the generator produces electricity with GHG emissions, then there is no regulatory system that gives legitimacy to a claim that the electricity generation did not produce GHG emissions, notwithstanding the fact that in the RPS program, imported non-renewable electricity is allowed to substitute for renewable to some degree. Renewable electricity produced at a generator that meets RPS eligibility requirements generally has low, or no, emissions, but there is no regulatory system for “null power.” Such a system, if it existed, would cause electricity to be deemed to have associated GHG emissions if the electricity is from a zero or low emission renewable source but the RECs have been separated (“unbundled”) from the electricity. The lack of a “null power” regulatory system means that double-counting of a zero-emission attribute of electricity can easily occur.

We believe the regulation harmonizes with the new approaches to RECs included in the 33 percent RPS requirement (SBX1 2), which replaced the Renewable Electricity Standard mentioned by the commenter. The new RPS mandate allows some use of ”unbundled renewable energy credits,” which we believe are essentially the same as “tradable RECs.” However, a utility is limited to using these unbundled RECs to meet 25 percent of its RPS requirement through 2013, 15 percent for the compliance period ending in 2016, and 10 percent thereafter.[7] A modified WREGIS could conceivably track renewable electricity, and we are considering whether WREGIS could be modified to do so, or another system created to track electricity deliveries.

Within WCI, there were stakeholder discussions regarding the use of RECs in reporting emissions from out-of-state electricity imports. Stakeholders were requested to submit their proposed option in the potential role for RECs within a cap-and-trade system. The WCI Electricity Team evaluated all of the discussion and stakeholder responses, and the implications of the three options posed. The Electricity Team made their recommendation to WCI Partners, who subsequently announced the decision, which we support. We continue to work with stakeholders on the issues described by the commenter.

I-77. (multiple comments)

[7] Public Utilities Code section 399.16(b)

Comment: SMUD strongly encourages the ARB to fully vet this topic before making a final decision. The WCI decision reverses legal definitions of RECs set forth in the Public Utilities Code, and relied on in energy contracts by dozens of covered entities. It throws into question the underlying value of the RECs tracked by WREGIS, effectively voiding the WREGIS definition, thereby creating further confusion about legal claims that can be made regarding contracts involving this commodity. The reasoning offered by the WCI decision is primarily that the administrative burden of tracking REC ownership and claims made by purchasers of null power ignore the new administrative burden that is created for the reporters of these transactions, who now have the very tool that was created to track renewable energy claims taken away, leaving them in a predicament of relying on vague language in a reporting regulation to base long term contracts on. Finally, the decision calls into question the claims that are made in the voluntary renewable energy markets around the benefits that are embedded in REC's, thereby undermining the value of this market perhaps in a bigger way than the decision of whether or not to create a set-aside.

In addition to fully capturing stakeholder input on this important topic, the ARB should consider the cost implications of adopting this policy on REC's. The use of REC's for RPS and RES compliance was intended to help reduce the high cost of building renewable energy. By requiring entities to purchase both the energy and the REC, the ARB is effectively eliminating, or greatly limiting the viability of REC's for use in the RES and RPS compliance. This policy will either increase costs under the RES or it will increase costs under the cap and trade as entities opt to purchase REC's and are required to come up with additional allowances. Considering the RES is one of the most expensive policies under the full set of AB 32 policies, and was expected to result in substantial reductions in the scoping plan, the ARB should give strong consideration to policy decisions which either inflate its cost or reduce its effectiveness in contributing to statewide emissions reductions.

Specific changes to the cap and trade regulation would be to recognize that all state-recognized renewable energy resources procured for either the Renewable Portfolio Standard (RPS) or Renewable Electricity Standard (RES) should not be required to have any compliance burden associated with their purchase. SMUD recommends adding a subsection (g) to Section 95852.2 (emissions without a compliance obligation), as follows:

<u>95852(g) Reserved for future consideration of treatment of combustion emissions associated with power delivered along with RECs.</u>

In the reporting regulation, language would explicitly be needed recognizing the use of WREGIS for tracking these renewable energy purchases. (SMUD1)

Comment: The regulation should be altered to treat RECs and out-of-state renewable resources as having zero GHG emissions commensurate with the underlying renewable resources that they represent, in order to harmonize with the renewable energy standard, eliminate potential duplication and tracking systems, and provide support for the voluntary market. We think that the current treatment of RECs in the reporting regulations could lead to hundreds of millions of dollars in additional costs and threaten the ability of the RES to deliver GHG reductions as expected. We do not believe this issue has been fully vetted with stakeholders and urge future consideration as requested in the joint utility letter that you've received. We'd like to see this issue added to the list of issues staff plans to workshop in 2011 or otherwise explicitly address some direction to staff for further resolution. (SMUD2)

Comment: SCE, PG&E, SDG&E, SMUD and NCPA are very concerned that the ARB's draft Cap-and-Trade and proposed amendments to the Mandatory Reporting Regulations do not recognize the greenhouse gas (GHG) reduction benefits of certain renewables contracts entered into to meet the State's renewables goals. The current version of the draft reporting regulations provide no mechanism to account for the zero GHG attributes of many out of-state renewable contracts and, as a result, would result in regulated parties having to retire allowances for these renewables resources. If this deficiency is not resolved, our customers and California will face the following:

- Hundreds of millions of dollars in increased costs to retire allowances for imported energy from contracts with renewable resources that are otherwise counted as renewable by State law.
- Inability of the State's 20 percent and 33 percent renewables programs to achieve the GHG reductions estimated by ARB since certain renewable contracts would be treated as GHG emitting.
- Upward pressure on allowance prices given increased demand for allowances needed to cover these renewable contracts.

The State's renewable programs are already identified by ARB as the highest cost GHG reduction measure and these costs should not be unnecessarily increased. California utility customers should receive credit for the GHG attributes that they have already purchased through their renewable contracts and should not be required to pay twice for their GHG benefits.

Fortunately, there is a workable solution to this problem-the use of the State's statutorily required system using WREGIS and renewable energy credits to count out-of-state purchases as RPS-eligible within the ARB's Mandatory Reporting Regulation. WREGIS has a deep foundation within the CPUC's decisions and California's renewables program. Accordingly, we urge the ARB to use this system to ensure that all renewable purchases eligible under the RES and RPS are credited as zero GHG. (PUBLICUTILITIES)

> **Response:** As recommended by SMUD, we held a workshop to consider RECs, renewable energy, and other topics associated with imported electricity on August 26, 2011. We do not agree that the regulation reversed legal definitions of RECs. SBX1 2 changed the definition of a renewable energy credit to:
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> > (h)(1) "Renewable energy credit" means a certificate of proof associated with the generation of electricity from an eligible renewable energy

resource, issued through the accounting system established by the Energy Commission pursuant to Section 399.25, that one unit of electricity was generated and delivered by an eligible renewable energy resource.

(2) "Renewable energy credit" includes all renewable and environmental attributes associated with the production of electricity from the eligible renewable energy resource, except for an emissions reduction credit issued pursuant to Section 40709 of the Health and Safety Code and any credits or payments associated with the reduction of solid waste and treatment benefits created by the utilization of biomass or biogas fuels.

This definition does not state under what circumstances a REC has value in California, nor does it say where the electricity would be delivered. WREGIS tracks RECs for many states, but California law and regulation determines their use in California. The CPUC has put forth that avoided emissions do not necessarily have any value in a GHG regulatory program. Even though they are included in a WREGIS Certificate, this does not mean that avoided emissions can be used in a GHG regulatory program.

Regardless of the WCI process, California's energy agencies have made it clear that RECs may have no value in a GHG regulatory program.

Furthermore, we agree that REC-only transactions may reduce the cost of renewable energy for RPS compliance. Requiring allowances for electricity from GHG-emitting power plants does nothing to limit the viability of RECs for use in RPS compliance. GHG regulation does not increase costs for RPS compliance; it merely imposes a compliance obligation on GHG-emitting power when that power is delivered into California.

The new RPS law over time reduces the amount of RECs that can used to meet a utility's RPS compliance requirements, with an exception for certain grandfathered use of RECs. In the first set of 15-day changes to the regulation, we added section 95802(a)(237) to recognize this transition by defining "replacement electricity" as electricity from GHG-emitting sources that, in limited circumstances described in new section 95852.2(b)(3), can be deemed to have the emissions of a variable renewable resource. We made this change because currently it is very difficult to deliver renewable electricity from variable renewable resources between balancing authority areas, and because there is a tradition of "firming" variable renewable power by substituting other electricity when, for example, wind dies down or clouds block the sun. Because renewable resources are using various strategies to deliver firm power, and because transmission system operations are evolving to enable delivery of variable renewable resources between balancing authority areas, we believe these changes are appropriate for variable resources which in their nature are not fully deliverable at this point. In the second set of 15-day changes to the regulation, we removed the "replacement electricity" definition and included provisions for an RPS adjustment, which we believe addresses the commenters' concerns.

I-78. Comment: Please make sure that RPS requirements and penalties are maintained or strengthened. Anything that creates incentives for utilities to invest in renewable generation is better in the long-run for the environment and our economy. And with increasing competition from emerging economies for natural gas, we must invest in energy independence. (BROWNRI)

Response: RPS requirements and penalties are established within the California Energy Commission and the Public Utilities Commission, and are not the subject of this regulation.

I-79. Comment: An approach that does not recognize the GHG attributes from RPS contracts is contrary to the RPS legislation and would arbitrarily increase costs for California customers. It also calls into question ARB's use of AB 32 as statutory authority to require 33 percent renewables as a GHG-reduction measure and could result in the State not achieving ARB's forecast GHG reductions from both the 20 percent and 33 percent renewable programs. (PGE1)

Response: Our approach is not contrary to the RPS legislation. We agree that electricity from RPS eligible generation has low or no GHG emissions in most cases. However, we believe that this regulation must account for the emissions of electricity imported into electricity, even if that electricity substitutes for RPS electricity. While we disagree that ARB does not have authority to require a 33 percent renewable electricity standard, it is not necessary for ARB to require such a standard because legislation requiring a 33 percent RPS has become law. ARB discontinued its efforts to complete its rulemaking process to establish a 33 percent Renewable Electricity Standard.

I-80. Comment: Please clarify the assignment of the emission level that goes with renewable energy credits. The emission level should be that of the underlying electricity generating resource that gave rise to the renewable energy credit. For example if a California utility purchases a renewable energy credit from a biomass project, the emission level that goes with that REC should be the emission level of the biomass project, not the system average. (NESCO)

Response: ARB does not assign emission levels to RECs. For delivered electricity, we use reported actual emissions to determine compliance obligations for delivered electricity.

I-81. Comment: Water agencies are in a unique position to offer additional opportunities for reducing greenhouse gas emissions associated with electricity use in California. In particular, the strategic deployment of renewable energy projects on water agency properties could provide significant early reductions in greenhouse gas emissions, along with other benefits such as improving the reliability of the state's energy supplies during peak use periods and reducing the load on the state's transmission lines. However, increasing the number of renewable energy projects within the water sector will depend on addressing current administrative and legislative obstacles that prevent these projects from going forward. Consideration should be given to making in-conduit hydropower an eligible technology for the self-generation incentive program. Large hydropower generation (more than 30 MW) should be recognized as a renewable energy source. (ACWA)

> **Response:** This comment is beyond the scope of the regulation. The California Energy Commission is the agency responsible for determining whether a technology or generator is RPS eligible.

Voluntary Renewables

I-82. (multiple comments)
Comment: We support the inclusion of the current placeholder language indicating that a voluntary renewable energy set-aside will be a part of California's emission trading program. Such a mechanism will provide crucial support for the continued growth in voluntary purchases of renewable energy in California in the years ahead. (UCS1, LUDLOW, WALTERS)

Comment: The provision to set aside/cancel permits to protect voluntary uptake of renewable electricity tariffs is welcome, continuing the principle set out in the Regional Green House Gas Initiative. The EU has failed to address the question of how to ensure caps do not prevent voluntary reductions, made beneath the cap, from delivering additional emissions savings. We will continue to point to developments in the US in our calls for similar measures to be introduced in Europe. (SANDBAGCC)

Comment: We believe including a set-aside for California's growing voluntary renewable energy market will help to further stimulate innovation in renewable energy, thus promoting new businesses and job growth, as well as reducing pollution. (SIERRACLUBCA4).

Comment: I want to express my appreciation on behalf of CEERT, the Global Warming Advocates Coalition and a number of clean energy companies and advocacy organizations for the inclusion of placeholder language for a set-aside of allowances on behalf of voluntary purchases of renewable energy. This provision, coupled with other policies, will provide crucial support to the continued growth of California's renewable energy industry and will bring a number of public health and environmental co-benefits as well as much needed jobs to the state of California. (CEERT)

Comment: The Council supports the allocation for a voluntary renewable energy allowance set-aside. (BCFSE)

Comment: We write to you in support of including a provision in the Cap and Trade Regulation to establish a Voluntary Renewable Energy Set-Aside. We believe including such a provision will help to further stimulate innovation in renewable energy, thus promoting new businesses and job growth, as well as reducing pollution. The proposed cap and trade program currently contains placeholder language indicating that a voluntary renewable energy set-aside will be part of California's emission trading program; specifically, placeholder language that would establish a voluntary renewable set-aside account (p. A-52) and the allocation to voluntary renewable energy allowance set-asides (p. A-77). Such a mechanism will provide crucial support for the continued growth in voluntary purchases of renewable energy in California in the years ahead. Clean energy development provides a host of co-benefits, not least putting California in a better position to meet the State's post-2020 goals. (KUSTIN09)

Comment: The proposed Cap and trade program currently contains placeholder language indicating that a voluntary renewable energy set-aside will be part of California's emission trading program; specifically, placeholder language that would establish a voluntary renewable set-aside account (p. A-52) and the allocation to voluntary renewable energy allowance set-asides (p. A-77). Such a mechanism will provide crucial support for the continued growth in voluntary purchases of renewable energy in California in the years ahead. Following the WCI recommendations, renewable energy generated within California and sold into the voluntary market should be eligible for the set-aside. (KUSTIN01)

Comment: SMUD supports consideration of a voluntary renewable energy allowance set-aside account. Section 95831(b)(6) reserves an account under the control of the Executive Director for the future creation of a portion of allowances set aside to support voluntary renewable activities. SMUD has consistently advocated for support for a voluntary renewable accommodation under the cap and trade program, and looks forward to working with ARB staff to establish the account in 2011. Failure to do so, in SMUD's opinion, will act to undermine our successful Greenergy Program and similar voluntary renewable purchasing efforts. (SMUD1)

> **Response:** We appreciate the commenters' support of the voluntary renewable energy set-aside. We modified section 95831(b)(6) and what was called a set-aside account is now the Voluntary Renewable Energy (VRE) Reserve Account.

I-83. Comment: There should be no cap on the budget adjustment for voluntary renewable energy. The ex-post true-up description in ARB's December 2009 Preliminary Review Draft (PDR) suggested that there would be a fixed cap ("predetermined percent") of the total allowances that could be used for the budget adjustment for VRE demand. 3Degrees urges ARB not to adopt a pre-determined cap and to allow the budget adjustment to be determined solely by the ex-ante estimate of need based on demonstrated demand.

It should not be the case that only some voluntary demand reduces emissions. Every emission-free megawatt hour (MWh) of renewable energy supported by voluntary demand offers the same greenhouse benefits and should be recognized by eligibility to retire allowances. A pre-determined cap would introduce risk and uncertainty regarding environmental claims. It is important that purchasers know that they will receive what they purchase.

The rationale for a cap on the administrative adjustment is usually to protect emitters from having to acquire scarcer (and possibly more expensive) allowances. But every renewable MWh generated to the grid reduces the number of MWh (and emissions) generated from other sources, thereby reducing the need for allowances. When both supply of and demand for allowances are reduced by an equal amount, the price of allowances should be unaffected. If there must be a cap on the number of allowances that can be placed in the holding account as an administrative adjustment, then there is no need to do the ex-ante estimate of budget adjustment for the voluntary market for renewable energy.

If ARB implements a cap on the Voluntary Renewable Electricity (VRE) set-aside, the fixed number or percent of allowances should simply be placed into the holding account. RGGI provides an example. Although the RGGI model rule envisioned that each state would conduct an ex-ante estimate of demand, most RGGI states (the exception being Massachusetts) opted to place a fixed number or percent of allowances in their administrator's accounts, rendering the ex-ante estimate administratively superfluous.

Should ARB decide to pursue a cap on the number of allowances that can be placed in the holding account, 3Degrees strongly recommends that the cap be subject to annual review and adjustment rather than at the start of each three-year compliance period, or that an automatic review be triggered whenever demand exceeds the cap for two years in succession. Several RGGI states have adopted a similar provision. (3DEGREES)

There should be no predetermined time limit on the VRE set-aside. ARB should bear in mind that it is through the addition of more renewables that the state will actually reduce carbon emissions in the electricity sector. A healthy and reliable voluntary market provides renewable energy developers with a clear market signal that additional long-term revenue is present to support new projects. This, in turn, leads to more investment and growth of renewables in California. The growth of demand for renewables, both voluntary and mandatory, provides evidence that the overall emissions cap can be lowered. 3Degrees sees no logical reason to curtail this positive trend by limiting the amount of time the VRE mechanism can contribute to reducing emissions.

The increased demand for renewables, both voluntary and mandatory, will lead to increased supply, which reduces greenhouse gas emissions and reduces the need for allowances overall. Term limiting a VRE set-aside threatens the investment in, and scaling of, renewable generation.

If ARB feels that it may be desirable to end the VRE set-aside at some point, it should not choose an arbitrary sunset date now when we have no evidence to support that move. Instead, it should undertake a general market review in the future to examine the evidence and determine, through a multiparty stakeholder process, that a sunset on the set-aside is merited. If ARB decides to end the VRE set-aside, it should be careful to base the sunset on the date of project installation, not on the date of the RECs or output. Renewable developers make investment decisions based on a set of assumptions about market support. If developers do not have the regulatory certainty to make informed decisions around future projects, then risk is increased and, subsequently, fewer projects are likely to be built. (3DEGREES)

> **Response:** We believe that allowing voluntary renewable electricity to retire allowances is a transitional strategy. In general, this regulation imposes costs on GHG-emitting activities under the cap and does not in any way give credit for any kind of activities within the capped sectors that do not emit GHGs. We make a temporary exception for voluntary renewable electricity so that during the early years of the cap-and-trade program, the voluntary market can continue to sell its product as something that reduces GHG emissions. We expect voluntary use of renewables to continue to increase as electricity users seek ways to produce their own, emission-free electricity, regardless of whether it reduces the cap. As allowance prices rise, and assuming that the cost of renewable electricity will continue to fall, electricity end-users will have increasing economic incentives to purchase electricity that is not subject to a carbon price, including voluntary renewables. We added section 95870.1(c) that provides for transfer of allowances to the VRE reserve account through the budget year 2020, which covers the entire period of the cap instituted with this regulation. New section 95870(c) provides for the transfer of allowances to the VRE Reserve Account. For 2013 and 2014, 0.5 percent of the allowances will be transferred, and for 2015-2020, 0.25 percent of the allowances will be transferred each year. Our internal analysis of VRE demand led to the conclusion that the amount transferred during the first two years will likely be sufficient to meet the full demand for VRE allowance retirement. Because this is a transitional program, we cut the annual VRE reserve account allocation by 50 percent for 2015-2020.

I-84. (multiple comments)
Comment: The proposed regulation includes two separate sections that carve-out special treatment for allowances to address voluntary renewable energy projects. In section 95831(c)(6) the regulation would create an Allowance Set Aside Account for Voluntary Renewable Energy Credits and in section 95870(e) the regulation would address the means by which that account would be funded. CARB must ensure that the reduction in available allowances does not result in increased compliance costs for utilities and other compliance entities. (NCPA1)

Comment: PG&E's overarching policy principles, with respect to AB 32 implementation, are to preserve the environmental integrity of the program, while managing customer costs. PG&E believes that any proposal that removes allowances from the market must align with these principles. Therefore, any proposal to remove or retire allowances to reflect voluntary renewables should preserve the environmental integrity of AB 32 and not increase the compliance costs for utility customers and other participants. To accomplish this, we believe that it is important that any allowances removed for voluntary renewables be linked to actual generation rather than potential generation, and be based on a rigorous emissions reduction methodology associated with this renewable generation. (PGE1)

Comment: The Utilities appreciate that CARB has deferred action on the Voluntary Renewable Energy Allowance Set-Aside (VRE) and agree that it is important to allow the market to develop fully before this program element is considered. The Utilities continue to have concerns with the inclusion of a set-aside account. If this set-aside is eventually added to the cap and trade program it will, by design, remove compliance instruments from the market leaving fewer allowances available for covered entities, which in effect reduces the cap below the goal set by AB 32. This would also increase the overall costs of compliance and the compliance burden for covered entities. The Utilities recommend revisiting this issue after the end of the first compliance period so as to have a sufficient base case for analysis, and at that time determine whether this type of option can be viably integrated into the cap and trade program without unintended consequences. (MID1)

> **Response:** We modified section 95831(c)(6) and added section 95841.1 to clarify the use of the VRE set-aside account, and the requirements for retirement of allowances based on VRE. This is a transitional program or strategy, to encourage continued voluntary investment in renewable electricity during the early years of the cap, by ensuring that real GHG reductions can be claimed for VRE that meets the regulation's requirements. We do not believe that the VRE program will reduce available allowances. Because VRE must be grid-connected, it will reduce the demand for electricity from utilities, including the demand for GHG-emitting electricity. Utilities can therefore reduce purchases of GHG-emitting electricity, thus reducing demand for allowances proportionally to the amount of VRE for which allowances are retired. Although CARB need not ensure that reducing available allowances does not increase compliance costs, we do not believe this is likely. Furthermore, the VRE requirement in new section 95841.1 ensures that allowances would only be retired for actual generation rather than potential generation.

I-85. Comment: VRE set-aside should be based on the location of the eligible generators, not on the location of the purchasers. 3Degrees fully supports a generator-based approach in which allowances are retired whenever RECs from a facility in ARB's territory are purchased and retired by a customer in the VRE market with no limitation on the customer's location. WCI recently recommended this approach to guide its VRE set-aside. However, it should be noted that RGGI has based its retirement of allowances for voluntary renewable energy on the location of the buyer. We believe this would be a mistake. It should not matter where the buyer is located, but rather on where the generator is located, for two reasons:

First, if a consumer located outside California purchases RECs from a renewable generator located within California, that purchaser would have the same effect on emissions in California as an in-state purchaser. Both would reduce emissions in California.

Second, in addition to lowering emissions in California, focusing on the location of the generator is good for the California economy by encouraging out-of-state demand and offering wider markets to California-based generators.

Whether the purchaser is located inside or outside California, RECs from eligible California generators should be retired. REC retirement will generally occur in WREGIS, but if the RECs are exported to another tracking system that serves the purchaser, these too should be accepted as long as they include the necessary information to tie them back to a California generator whose RECs were originally issued by WREGIS.

The problem with basing the adjustment on the location of the renewable energy customer (i.e., limiting it to California purchasers) is that it would unnecessarily restrict the benefits to California—the economic benefits to California generators noted above, and the emission reduction benefits to California, because out-of state purchasers would be reluctant to buy from California generators if they cannot claim emission reductions. This would lead to smaller and balkanized markets for renewable energy as other states would follow California's lead. Limiting markets in this way would reduce competition and could lead to higher REC prices. (3DEGREES)

> **Response:** We agree and new section 95841.1, by requiring direct delivery of VRE electricity, bases the set-aside on the location of the generator, and not the purchaser.

I-86. Comment: 3Degrees would like to emphasize that the creation of a VRE set-aside to support renewable energy is most effective when other geographic partners create reciprocal arrangements. ARB has signaled that it intends to integrate its climate efforts with other cap and trade programs, and that it may also fashion its VRE set-aside on WCI's structure. 3Degrees encourages ARB to press for similar treatment of voluntary renewable energy among WCI's partners. Just as renewable energy generated in California and sold to voluntary buyers in New Mexico should result in retirement of California allowances, so should renewable energy generated in New Mexico and sold to voluntary buyers in California result in the retirement of a New Mexico allowance.

Further, when integrating ARB's design with WCI, there should be no state- or province-specific restrictions that balkanize the VRE market. Despite WCI's reluctance to require harmonizing its jurisdictional rules on a VRE set-aside and defining renewable generator eligibility requirements, such a uniform definition of eligible resources could account for an administrative adjustment to each partner's base budget. (3DEGREES)

Response: Although no response is required because this comment does not address the regulation, we agree that harmonization of the VRE approach throughout WCI is desirable.

I-87. Comment: The administrative adjustment to the budget should be done annually rather than for a three-year compliance period. The previously published Discussion of Concept contemplates an adjustment to the base budget for each compliance period, which is three calendar years. We recommend that the administrative adjustment for voluntary renewable energy demand be made annually so that voluntary buyers and sellers do not have to wait for three years or longer to be certain of the effect of their purchases. Annual reporting, verification and adjustments would also ensure that participants remain familiar with the administrative actions necessary to support environmental claims, and submit timely reports.

Another reason for making the administrative adjustment annually is that it would be more accurate to do a one-year projection of voluntary demand than a three-year projection. Voluntary demand may be more sensitive to annual fluctuations in general economic conditions as well as to price fluctuations based on year-to-year variations in supply and demand. A one-year ex-ante estimate of the budget adjustment needed would be more likely to reflect current conditions. An annual adjustment and retirement of allowances would also be consistent with the Green-e Energy standard for annual verification of purchases and retirements. This is important because Green-e Energy certifies the vast majority of voluntary renewable energy products.

The ex-post true-up of budget adjustments should true-up in both directions. The PDR also addressed the ex-post true-up of budget adjustments. The Discussion of Concept states, “Any earmarked allowances that resulted from the overestimation of expected reductions vs. claimed reductions could be released in the subsequent compliance period.” That is a true-up in one direction, when voluntary demand is less than the ex-ante adjustment, but there is no equivalent true-up in the other direction, when voluntary demand exceeds the ex-ante adjustment. In fact, the PDR states, “In no event could the size of this adjustment exceed a predetermined percent of the total allowances from the compliance period in question.” This is not a real true-up if it only goes in one direction. 3Degrees recommends that any shortage for a given year be remedied by increasing the succeeding year’s ex-ante adjustment by the amount of the shortage, and immediately (in the new year) retiring allowances commensurate with the shortage.

If this cannot be done, then ARB should adopt a policy of not releasing any excess allowances in the holding account, and instead carrying them forward to be used in any year when voluntary demand exceeds the ex-ante adjustment for that year. This issue is critical because it will be impossible to ensure that a purchase is meaningful if it is uncertain that it will result in the retirement of equivalent allowances. Purchasers have to know that they are going to get what they think they are buying.

The ex-ante estimate of budget adjustment needed should be based on WREGIS data. The PDR suggests that the National Renewable Energy Laboratory (NREL) provide an estimate of voluntary renewable energy demand for the ex-ante budget adjustment. NREL is an outstanding institution, and is the source of a great many useful reports and analyses, but it has limited access to data on the location of the renewable generators that produce the electricity and renewable energy certificates (REC). Generator location data is critical for ARB's purpose because any adjustment that is made to the emissions budget should be based only on generation located in California or in WCI states whose emissions are similarly capped.

To create the ex-ante estimate, ARB should first establish the most recent annual demand (we will call it the baseline), then update that using recent growth in demand to estimate the necessary adjustment to the upcoming budget year. The best source for baseline data—based on accuracy, comprehensiveness and administrative convenience—is the Western Renewable Energy Generation Information System (WREGIS). Each certificate issued by WREGIS contains vital information about the energy source, generator location, date the generator began commercial operation, and other attributes of the MWh generated. WREGIS also assigns each certificate a unique serial number, a fact which is essential to verification of no double counting. WCI has already recommended its partners use an established REC tracking system like WREGIS as the basis for allowance retirements from a VRE set-aside.

WREGIS is also ideal to this task because it is comprehensive. It includes all RECs issued to California generators registered in WREGIS, regardless of whether those RECs are sold as an unbundled product, bundled with electricity and sold as green power, or generated by distributed generation and consumed onsite.

Retail sellers of renewable electricity or RECs should have to indicate in their WREGIS accounts the number and serial numbers of the certificates sold to (and retired for) voluntary purchasers. Again, the certificates will indicate whether they were issued to California generators or to generators in other capped states. After the end of a calendar year, WREGIS could then produce a report showing the sum total of voluntary sales from eligible California (or WCI partner) generators.

For the second step in the ex-ante estimate, ARB (or the California Energy Commission, or NREL for that matter) would project the baseline ahead to the upcoming budget year using the percentage change in voluntary renewable energy sales between the two most recent years with full data. To illustrate, let us assume that we are in 2011 and that we need to estimate the adjustment to the 2012 base budget. ARB would obtain a report from WREGIS on voluntary sales from eligible generators for calendar year 2010. The 2010 baseline would be adjusted two years to 2012 by using the annual growth rate in voluntary sales, also shown by WREGIS reports, from 2009-2010. This approach is not complicated, uses highly reliable data, and could be done and reported out by ARB staff showing all data and calculations for transparency.

The final step in the ex-ante adjustment would be as described in the PDR's Discussion of Concept. Using the projection of voluntary demand in MWh, ARB would calculate, using a California-appropriate emissions factor, a commensurate number of allowances representing reduced emissions due to this expected level of voluntary demand for eligible renewable energy. This number of allowances would then be withheld from the base budget, and earmarked and held in ARB's holding account. (3DEGREES)

> **Response:** Although these comments were submitted during the 45-day comment period, they do not address the regulation, but instead address the preliminary draft regulation (PDR) which was released before the beginning of the regulatory process. When the regulation was released, section 95831(b)(6) created the VRE Reserve Account, but staff continued to work with stakeholders to craft the language regarding the allowance budget for the account, the yearly allocations, and the rules for retirement of allowances. We took into account the comments of 3DEGREES and many other stakeholders and modified section 95831(b)(6) and added sections 95841.1 and 95870(c) to provide for retirement of allowances from the VRE Reserve Account to encourage VRE. We believe our regulatory approach to the allowance budget provides the best certainty for the market, and will encourage rapid development of voluntary renewable electricity in the early years when most needed. This is a transitional program and reduces the VRE allocation in the later years of this regulation, because we expect the price effect of the regulation to continue to encourage VRE even if though the set-aside percentage will be reduced after 2014.

I-88. (multiple comments)
Comment: ARB's December 2009 Preliminary Review Draft (PDR) suggested that there would be a fixed cap ("predetermined percent") of the total allowances that could be used for the budget adjustment for VRE demand. REMA urges ARB not to adopt a pre-determined cap and to allow the budget adjustment to be determined solely by the ex-ante estimate of need based on demonstrated demand.

It should not be the case that only some voluntary demand reduces emissions; every emission-free mega-watt hour (MWh) of renewable energy supported by voluntary demand offers the same greenhouse benefits and should be recognized by eligibility to retire allowances. A pre-determined cap would introduce risk and uncertainty regarding environmental claims. Again, it is important that purchasers know that they will get what they think they are purchasing. The rationale for a cap on the administrative adjustment is usually to protect emitters from having to acquire scarcer (and possibly more expensive) allowances. But every renewable MWh generated to the grid reduces the number of MWh (and emissions) generated from other sources, thereby reducing the need for allowances. When both supply of and demand for allowances are reduced by an equal amount, the price of allowances should be unaffected. If there must be a cap on the number of allowances that can be placed in the Holding Account as an administrative adjustment, then there is no need to do the ex-ante estimate of budget adjustment for the voluntary market for renewable energy. Should ARB implement a cap on the VRE set-aside, the fixed number or percent of allowances should simply be placed into the Holding Account. RGGI provides an example. Should ARB instead to pursue a cap on the number of allowances that can be placed in the Holding Account, REMA strongly recommends that the cap be subject to periodic review and adjustment prior to the start of each three-year compliance period, or that an automatic review be triggered whenever demand exceeds the cap for two years in succession.

Prohibit a time limit on the VRE set-aside. If renewable technology costs become competitive, and there is sufficient supply relative to demand that REC prices are low, we can put more renewables on the grid, reduce greenhouse gas emissions, and thereby reduce the need for allowances. While RGGI has not incorporated such as limit, and no RGGI members have embraced it, WCI has recommended that its partner jurisdictions choose "whatever time limit" (if any) that is found appropriate for that jurisdiction." If ARB nevertheless feels that it may be desirable to end the VRE set-aside at some point, it should not choose an arbitrary sunset date now when we have no evidence to support that move. Instead, it should undertake a general market review in the future to examine the evidence and determine, through a multiparty stakeholder process, that a sunset on the set-aside is merited. Finally, if ARB decides to end the VRE set-aside, it should be careful to base the sunset on the date of project installation, not on the date of the RECs or output. Term limiting a VRE set-aside threatens the investment in and scaling up of renewable energy generation.

REMA fully supports a generator-based approach in which allowances are retired whenever RECs from a facility in ARB's territory are purchased and retired by a customer in the VRE market with no limitation on the customer's location. It should not matter where the buyer is located, but rather on where the generator is located, for two reasons:

- If a consumer located outside California purchases RECs from a renewable generator located within California, that purchaser would have the same effect on emissions in California as an in-state purchaser. Both would reduce emissions in California.
- In addition to lowering emissions in California, focusing on the location of the generator is good for the California economy by encouraging out-of-state demand and offering wider markets to California-based generators.

REC retirement will generally occur in WREGIS, but if the RECs are exported to another tracking system that serves the purchaser, these too should be accepted as long as they include the necessary information to tie them back to a California generator whose RECs were originally issued by WREGIS. The problem with basing the adjustment on the location of the renewable energy customer (i.e., limiting it to California purchasers) is that it would unnecessarily restrict the benefits to California. Limiting markets in this way would reduce competition and could lead to higher REC prices.

REMA would like to emphasize that the creation of a VRE set-aside to support renewable energy is most effective when other geographic partners create reciprocal arrangements. ARB has signaled that it intends to integrate its climate efforts with existing programs like WCI, and that it may also fashion its VRE set-aside on WCI's structure. REMA encourages ARB to press for similar treatment of voluntary renewable energy among WCI's partners. Just as renewable energy generated in California and sold to voluntary buyers in Oregon should result in retirement of California allowances, so should renewable energy generated in Oregon and sold to voluntary buyers in California result in the retirement of an Oregon WCI allowance. Further, when integrating ARB's design with WCI, there should be no state or province-specific restrictions that balkanize the VRE market. Despite WCI's reluctance to require harmonizing its jurisdictional rules on a VRE set-aside and defining renewable generator eligibility requirements, such a uniform definition of eligible resources could account for an administrative adjustment to each partner's base budget.

The previously published ARB Discussion of Concept contemplates an adjustment to the base budget for each compliance period, which is three calendar years. We recommend that the administrative adjustment for voluntary renewable energy demand be made annually so that voluntary buyers and sellers do not have to wait for three years or longer to be certain of the effect of their purchases. Annual reporting, verification and adjustments would also ensure that participants remain familiar with the administrative actions necessary to support environmental claims, and submit timely reports. Another reason for making the administrative adjustment annually is that it would be more accurate to do a one-year projection of voluntary demand than a three-year projection. Voluntary demand may be more sensitive to annual fluctuations in general economic conditions as well as to price fluctuations based on year-to-year variations in supply and demand. A one-year ex-ante estimate of the budget adjustment needed would be more likely to reflect current conditions. An annual adjustment and retirement of allowances would also be consistent with the Green-e standard for annual verification of purchases and retirements. This is important because Green-e certifies the vast majority of voluntary renewable energy products.

The PDR also addressed the ex-post true-up of budget adjustments. The Discussion of Concept states, "Any earmarked allowances that resulted from the overestimation of expected reductions vs. claimed reductions could be released in the subsequent compliance period." That is a true-up in one direction, when voluntary demand is less than the ex-ante adjustment, but there is no equivalent true-up in the other direction, when voluntary demand exceeds the ex-ante adjustment. In fact, the PDR states, "In no event could the size of this adjustment exceed a predetermined percent of the total allowances from the compliance period in question." This is not a real true-up if it only goes in one direction. REMA recommends that any shortage for a given year be remedied by increasing the succeeding year's ex-ante adjustment by the amount of the shortage, and immediately (in the new year) retiring allowances commensurate with the shortage. If this cannot be done, then ARB should adopt a policy of not releasing any excess allowances in the Holding Account, and instead carrying them forward to be used in any year when voluntary demand exceeds the ex-ante adjustment for that year. This issue is critical because it will be impossible to ensure that a purchase is meaningful if it is uncertain that it will result in the retirement of equivalent allowances. Purchasers have to know that they are going to get what they think they are buying.

The PDR suggests that the National Renewable Energy Laboratory (NREL) provide an estimate of voluntary renewable energy demand for the ex-ante budget adjustment.

NREL is an outstanding institution, and is the source of a great many useful reports and analyses, but it has no data on the location of the renewable generators that produce the electricity and renewable energy certificates (REC). Generator location data is critical for ARB's purpose because any adjustment that is made to the emissions budget should be based only on generation located in California or in WCI states whose emissions are similarly capped. To create the ex-ante estimate, ARB should first establish the most recent annual demand (we will call it the baseline), then update that using recent growth in demand to estimate the necessary adjustment to the upcoming budget year. The best source for baseline data—based on accuracy, comprehensiveness and administrative convenience—is the Western Renewable Energy Generation Information System (WREGIS). Each certificate issued by WREGIS contains vital information about the energy source, generator location, date the generator began commercial operation, and other attributes of the MWh generated. WREGIS also assigns each certificate a unique serial number, a fact which is essential to verification of no double counting. WCI has already recommended its partners use an established REC tracking system like WREGIS as the basis for allowance retirements from a VRE set-aside. WREGIS is also ideal to this task because it is comprehensive. It includes all RECs issued to California generators registered in WREGIS, regardless of whether those RECs are sold as an unbundled product, bundled with electricity and sold as green power, or generated by distributed generation and consumed onsite. Retail sellers of renewable electricity or RECs should have to indicate in their WREGIS accounts the number and serial numbers of the certificates sold to (and retired for) voluntary purchasers. Again, the certificates will indicate whether they were issued to California generators or to generators in other capped states. After the end of a calendar year, WREGIS could then produce a report showing the sum total of voluntary sales from eligible California (or WCI partner) generators. For the second step in the ex-ante estimate, ARB (or the California Energy Commission, or NREL for that matter) would project the baseline ahead to the upcoming budget year using the percentage change in voluntary renewable energy sales between the two most recent years with full data. The final step in the ex-ante adjustment would be as described in the PDR's Discussion of Concept. (REMA)

Comment: We are concerned about the WCI recommendation that RECs have no role in cap and trade accounting. In the spring of 2010, the Western Climate Initiative (WCI) announced a recommendation to Partner states and provinces that, in a nutshell, unbundled REC purchases by regulated entities in the electricity sector should not reduce their compliance obligation. On May 27, 2010, CRS submitted a comment letter explaining the reasons why we believe this approach is misguided. Not least, this counters accepted best practice that null power should be assigned a system power profile. The approach would undermine the commonly accepted definition of RECs as containing the environmental benefits of the renewable energy generation that produced the REC. This hard-won and now commonly accepted definition has been enshrined in existing contracts and has facilitated impressive growth in the voluntary market over the past five years.

In response to concerns such as these, we understand that WCI's final recommendations for a VRE set aside were changed to explicitly suggest that specified null power be made be eligible for the set aside. From page 3: "WCI Partner jurisdictions should also consider requiring that renewable energy produced by VRE-eligible facilities in a non-WCI Partner jurisdictions and sold on a specified basis to the WCI Partner jurisdiction be counted as if those facilities were located in the WCI Partner jurisdiction."

We appreciate that perspectives such as those we have been offering appear to have been heard and responded to with this adjustment to the operation of the VRE Set Aside. Though we would prefer a more direct approach, whereby RECs do affect carbon accounting and null power carries associated emissions, in the absence of this first best outcome, we would support the inclusion of specified null power under the VRE Set Aside.

We do not believe that the draft Cap and Trade rule directly addresses this issue of REC accounting; however, we understand CARB is planning to follow the WCI recommended approach. That approach did not include a participatory process, not even the more limited participation usually offered as part of WCI policy development. A whitepaper discussing options was released, but there was no proposed recommendation with an opportunity to comment.

Though we see no indication that CARB is on the cusp of committing to a policy that constructs an artificial wall between RECs and carbon accounting, we reiterate that we think this would be a bad idea even with the inclusion of null power in the VRE set aside. Such a policy would create new accounting challenges and complications for existing contracts.

The VRE set aside will support the continued growth of voluntary purchases of renewable energy from both distributed generation and utility-scale facilities based within the state. These purchases are private funds going to expand clean energy generation in California. Given that this has been one of the bright spots in the California economy, policy choices to support continued growth only makes sense. As CARB has recognized, without such a VRE Set Aside, California clean energy producers wishing to sell into the voluntary market would be hampered by the fact they would no longer be able to correctly say that such purchases would lead to net emission reductions. There is demonstrated appetite amongst Californians for investment in voluntary action to reduce greenhouse gas emissions. The inclusion of a VRE Set Aside ensures that an in-state clean energy option continues to exist for these funds. (CRS)

Comment: NextEra Energy was pleased to see ARB recognize the importance of the voluntary renewable energy market. We look forward to working with ARB in developing sections 95870(e) and 95831 (c)(6) in 2011. An accounting mechanism for voluntary renewable energy purchases needs to be established to allow renewable energy projects located within California to participate in the voluntary renewable energy market. This can be accomplished most effectively through an off the top set-aside pool of allowances. Similar programs have been established in 9 of 10 RGGI states. The contribution from the voluntary purchase renewable energy credits to the development of new clean energy projects should not be ignored. The clean energy development that the off-the-top approach provides will put California in a better position to meet its long term goals (i.e. post-2020). The additional early (i.e. pre-2020) clean energy development will mean less reductions will have to be found in the long term, which will potentially reduce future allowance prices. Again, there are many other environmental and economic benefits beyond these reduced allowance prices.

The voluntary renewable energy set-aside should be estimated in advance of each compliance period and then the appropriate volume of allowances removed from total pool of allowances created under the cap. Information from the National Renewable Energy Laboratory, the Western Region Electricity Generation Information System, and other public data sources should serve as the basis for determining the quantity of allowances to be set-aside under the cap in advance of each compliance period. At the end of a compliance period, program administrators should reconcile voluntary demand estimates with actual generation. The difference between estimated and actual demand can be accounted for by adding to or subtracting from the set aside for the next compliance period.

ARB should consider the location of the renewable energy generator for eligibility. The RGGI program provides useful insight into how an off-the-top system can work. (NEXTERAENERGY)

> **Response:** The comments do not address the regulation. They address the PDR, the WCI process, and other documents prepared for discussion prior to the start of the formal rulemaking process for the cap-and-trade regulation. These comments, however, shaped the regulation submitted for formal rulemaking.
>
> Because of the transitional nature of this program, we have set the percentage of allowances allocated each year to the VRE Reserve Account. Setting a percentage of allowances, reducing the amount in later years, and sunsetting the program are all part of our transitional approach. Therefore we did not follow the recommendations of REMA and others that would prefer a permanent, demand-based approach. We reiterate that, in the future, the price effect is expected to provide an incentive to produce electricity that is GHG-emission free. Thus, in the future, a set-aside of allowances for VRE should not be necessary to support the VRE market.

I-89. (multiple comments)
Comment: We request the implementation of the proposed rule provision that provides for "Voluntary Renewable Energy Allowance Set-asides" under Sub Article 8, Disposition of Allowances, section 95870 (e), as soon as the cap is implemented. The set-aside allowance pool needs be maintained of sufficient size to encourage and stimulate renewable energy projects. These set-aside allowances should be preferably

limited and made available only to renewable energy projects that are determined to be "additional" and surplus, similar to that which must be demonstrated for an "offset" or emission reduction credit project. Projects eligible for the set-asides need to be those that would not have taken place under baseline "business as usual" market conditions. This requires a demonstration that without the value of the set-aside allowance, the renewable energy project economics would not be favorable. Specifically this should include projects which utilize biomass wastes that would have otherwise been open burned. We further recommend the GHG value of the set-aside allowance be determined using the average statewide GHG electricity emissions factor from the previous year (tons GHG per MWh electric). (PCAPCD)

Comment: Following the WCI recommendations, renewable energy generated within California and sold into the voluntary market should be eligible for the set-aside. (KUSTIN09)

> **Response:** We modified section 95831(b)(6) and added sections 95841.1 and 95870(c) which will implement the Voluntary Renewable Energy “set-aside” program allowing retirement of allowances from the VRE Reserve Account pursuant to section 95841.1. We believe our approach provides an incentive for VRE projects that will be additional, and that those projects would not take place without this incentive. Section 95841.1 makes renewable energy generated in California and sold into the voluntary market eligible for the “set-aside,” provided the participants meet the requirements of that section.

I-90. Comment: ARB should enable linkage of voluntary renewable energy set-asides with WREGIS. The proposed regulation provides for a Voluntary Renewable Energy Allowance Set-Aside Account. PacifiCorp believes that additional provisions towards preventing adverse impacts on the voluntary renewable energy (VRE) market would improve the proposed regulation. If ARB does include provisions for VRE allowance set-aside, the accounts to track VRE should be closely coordinated with the existing tracking mechanisms in WREGIS.

PacifiCorp also believes that if ARB removes allowances from the cap and trade market to reflect voluntary renewables, it should also preserve the environmental integrity of AB 32 and not increase compliance costs for utility customers and other participants. Any allowances removed for VRE should be linked to actual generation, not potential generation, and be based on a rigorous emissions reduction methodology associated with this renewable generation. (PACIFICOR1)

> **Response:** We added additional provisions sections 95841.1 and 95870(c), in part to prevent adverse impacts on the Voluntary Renewable Energy market, and we require reporting of RECs, which are issued through WREGIS, in section 95841.1(b)(2 and 3). Retirement of allowances requires actual, not potential, generation.

I-91. Comment: CIPL supports the Voluntary Renewable Energy Set-Aside. We understand that "voluntary associated entities" such as non-profit groups will be able to participate fully in the secondary markets and auctions. As legal non-profit organizations, many religious congregations are installing solar panels and undertaking other carbon-reducing measures at their facilities. With the implementation of an off-the-top voluntary renewable energy set-aside program, congregations would be assured that their actions are resulting in net emissions reductions. CIPL looks forward to working with the Air Resources Board as it develops the specific mechanisms to encourage voluntary purchases of renewable energy. (CIPAL)

> **Response:** We appreciate the support. Congregations will be able to participate in the VRE set-aside program pursuant to new section 95841.1.

Other

I-92. Comment: The renewable energy program and the GHG reduction program complement each other in that they both will reduce GHG emissions. And, both could place a substantial financial burden on ratepayers. A GHG Program that would require utilities to purchase GHG allowances while at the same time the utilities are committing substantial resources to procure renewable energy will take its toll on the financial stability of the utilities. The reality is that the ratepayer will pay for the utilities efforts to reduce GHG. To also pay for the allowances would be asking the ratepayer to pay twice and not be assured that they would see the financial benefits returned in their electric bills. We believe that the distribution of the allowances will be critical to the success of the program. There have been several proposals that very well could shift the compliance burden from one utility to another (or one region of California to another). For example, this could happen by using data from programs such as conservation, energy efficiency and renewable energy. Then, using this information to estimate the GHG reductions that were accomplished, and then using this information as the basis to provide additional allowances to a utility. These extra allowances would then be removed from another utility to maintain the established allowance cap. The utility with the reduced allowance would be placed at a disadvantage in achieving compliance with the Program goals. If ARB is considering this method, then we recommend that ARB increase the initial sector allocation to allow for the adjustments with a goal that no electric utility will have a shortfall and receive less than its original allocation. However, any program that has to rely on estimates or projections for crediting GHG emission reductions is suspect. Therefore, we recommend and support a program that utilizes a utility's GHG emissions, as reported to ARB, as the bases for determining the allocation of allowances. The resultant allocation program would be fair, straightforward, understandable and provide regulatory certainty. (WPA)

> **Response:** The allocation of allowances to utilities is based on consideration of the cost burden and early investment in emission reductions of each utility. We determined the cost burden by using utilities' plans for generation to supply their load through 2020, including the effect of policies such as the RPS and energy efficiency programs. The utilities as a group support the allocation method. We

believe that the allocation to utilities does not place any utility at a disadvantage. Furthermore, we modified section 95892(a) to clearly state that “Any allowance allocated to electrical distribution utilities must be used exclusively for the benefit of retail ratepayers.” We believe the number of allowances allocated to utilities coupled with this provision will create a good balance between allowing the pass through of carbon cost through utility rates to incentivize reduced GHG emissions, and protecting ratepayers from the full impact of both the renewable energy requirements (e.g., the RPS) and carbon costs utilities face in generating or procuring electricity.

I-93. Comment: 3Degrees would like to emphasize that the creation of a VRE set-aside to support renewable energy is most effective when other geographic partners create reciprocal arrangements. ARB has signaled that it intends to integrate its climate efforts with other cap and trade programs, and that it may also fashion its VRE set-aside on WCI’s structure. 3Degrees encourages ARB to press for similar treatment of voluntary renewable energy among WCI’s partners. Just as renewable energy generated in California and sold to voluntary buyers in New Mexico should result in retirement of California allowances, so should renewable energy generated in New Mexico and sold to voluntary buyers in California result in the retirement of a New Mexico allowance. (3DEGREES)

Response: This comment does not address the regulation. However, we added section 95841.1, which requires direct delivery of renewable VRE electricity among other conditions for the retirement of allowances in the VRE set-aside program. This provision helps ensure that VRE energy cannot be double-counted.

Combined Heat and Power (CHP)

Organizing Comments

I-94. (multiple comments)
Comment: Electric distribution utilities as a group will receive an allowance allocation roughly equivalent to 90 percent of their historical emissions for 2012. Facilities that produce electricity on-site (owned by the industrial entity, as opposed to a third-party facility physically on-site but considered off-site in the proposed regulation) and that qualify for Industry Assistance and are classified as High Leakage Risk will also likely receive a high percentage of their required allowances in a free allocation. All other CHP facilities that supply electricity to industrial hosts will be required to purchase a higher percentage or all of their required allowances. The proposed allowance allocation strategy does not create a level playing field for all electricity suppliers and may provide a disincentive to operate or install CHP. The potential for a level playing field is slim, unless the auction proceeds used for ratepayer protection are thoughtfully and equitably directed. Third-party electricity suppliers to industrial hosts eligible for assistance should receive allowance allocations comparable to those received by the

distribution utilities. No such protection is envisaged in the proposed regulation for CHP installed at sites not considered a leakage risk. (CACC)

Comment: The ISOR makes clear ARB's intent to cover the carbon costs of EITE entities' energy use to ensure they remain competitive and to avoid leakage. Depending on the mechanics of allocation, the proposed regulation could miss the mark. EITE entities have four primary options to procure electricity, and the proposed regulation provides certainty for emissions cost recovery for only one of those options. If an EITE entity produces and consumes power "on-site", its carbon costs will be covered. (2) If an entity procures power from its interconnected utility, through (3) self-generation that may not be located "on-site", or under a PUC Code section 218(b) over-the-fence transaction, the regulation is unclear about the level of coverage. To achieve CARB's stated objective, the proposed regulation should be revised to provide for carbon cost recovery by an EITE entity regardless of the entity's source of electricity. Specifically, if relying on the existing framework, CARB should provide that:

- An IOU or POU must convey free allowance value to an EITE entity through a rebate or bill credit, rather than through potential access to energy efficiency programs; alternatively, CARB should allocate free allowances to cover EITE entities' costs of carbon embedded in utility purchased power and deduct those allowances from the utility allocation.

- An EITE entity importing power from a non-utility generator through non-utility facilities should receive a free allowance allocation to cover the cost of carbon emissions associated with these imports.

- Any form of "self-generation" should be covered by a free allowance allocation provided the delivery of the power does not rely on utility delivery.

With these changes, CARB can be assured that the carbon costs associated with electricity consumed by all EITE entities will be covered in a competitively neutral way without risk of double recovery.

Market recovery of carbon costs: CARB should state its intent that CHP delivering power to the grid has a sufficient opportunity to recover carbon costs in the market price and provide for periodic review of market prices to assure that coverage.

Based on the existing regulatory framework, if an entity imports its power from a utility, the utility should be required to provide a direct rebate to cover those costs. (Alternatively, to ensure that all EITE entities importing power are treated equally, CARB could provide a direct allocation of allowances to these entities to cover carbon costs associated with imports). If an entity self-generates or purchases power over private wires from a non-utility, the carbon costs associated with the power should be recoverable through a direct allowance allocation. (EPUC)

Comment: For Combined Heat and Power (CHP), the regulation bases allocation for exported power from CHP on an assumption of carbon price recovery. The regulation must put in place provisions to monitor and ensure cost recovery. There needs to be assurance that third party CHP's serving the industrial sector receive free allocations for emissions related to the energy provided to the industrial sector on the same basis as if they were included in the sector. (WSPA1, WSPA2)

Comment: The Scoping Plan identifies 4000 MWs of new CHP by 2020. A key emission reduction measure is the proposed cap and trade program. Its effect on combined heat and power (CHP) is of significant concern to the CCDC1. California Clean DG Coalition (CCDC) represents "Onsite CHP" where the system, typically less than 20 MW, is sized to the electric and thermal needs of the commercial and industrial customer. We confirmed with staff that several issues will need to be addressed after Board action on December 16. These issues deal with the flow-through of free allocations from the utilities to CHP owners, what constitutes the marginal plant for purposes of calculating GHG reductions, and education and outreach. We ask for Board direction to the staff to work with CCDC so that the ARB can achieve its goals for this technology sector. (CACDGC)

> **Response:** We agree that the carbon costs energy-intensive, trade-exposed industrial emitters (EITEs) incur from purchased electricity is an important issue. We are working to ensure a level playing field for all sources of purchased electricity. The overall approach for the cap-and-trade regulation is based on the need to internalize the cost of GHG emissions and create a price signal that will encourage investment in the most cost-effective emission-reduction projects.
>
> Electricity utilities are allocated allowances to cover part of the total cost burden on utilities. These costs include the costs of the 33 percent renewable portfolio standard, costs utilities will face to purchase allowances for their own emissions to the extent that they own emitting power plants, and costs passed through from merchant power plants and cogeneration plants that must purchase allowances. Furthermore, section 95892(a), as modified, requires that any allowances allocated to utilities be used exclusively for the benefit of retail ratepayers.
>
> The approach for allocating allowances outside of the electricity industry is to compensate EITEs for the portion of carbon costs needed to ensure that California industry can remain competitive. Most EITE facilities are allocated allowances based on the Product Output-Based Allocation methodology pursuant to section 95891(b).
>
> With this methodology, benchmarks are calculated for distinct industrial sectors, and allowances are proportional to product output. For industrial sectors that are at risk and eligible for assistance but for which a product based benchmark is not appropriate, allocations are made based on an benchmarks calculated using the Energy-Based Allocation Calculation Methodology set forth in section 95891(c). For these sectors, allocations are proportional to the use of fuel and steam.

In the calculation of both kinds of benchmarks, an adjustment factor was not made for power purchased from utilities or from non-utility providers of electricity because of the uncertainty about how purchased power will create an indirect carbon cost. It is ARB's goal to see an appropriate carbon price properly embedded in all utility rates and in the power sold from non-utility providers. In establishing the appropriate carbon price in rates, we may need to account for other greenhouse gas-reducing policies, including the 33 percent renewable portfolio standard and the impact of these programs on electric rates. We continue to work with CPUC, CEC, and the publicly owned utilities to ensure that proper carbon pricing occurs.

Once we determine to what degree EITEs face indirect carbon costs from purchased power, we could potentially incorporate compensation for these costs into the product benchmarks to help minimize leakage. Alternatively, reductions in these costs could be created in some other fashion. We will revisit this issue once the California Public Utilities Commission Proceeding addressing utility costs and revenue issues associated with greenhouse gas emissions concludes.

We do not believe that the playing field is tilted against CHP facilities that are not part of EITEs (i.e., do not produce their own generation on site). It is true that independent CHP facilities incur carbon costs, but they can generally pass through the cost of carbon to the industrial entities that purchase the electricity and thermal energy that they generate. Thus, when they pass through the costs, they are compensated through the price they charge for their products, and no protection is needed. We note that some CHP commenters assert they will not be able to pass through costs due to their long-term contracts; we respond to this issue separately. It is important for carbon costs to provide such a price signal in order to provide market incentives to use products (including electricity and thermal energy) that are less carbon intensive.

Finally, in response to the request from CACDGC and others, the Board, in its resolution, directed the Executive Officer to review the treatment of CHP facilities in the cap-and-trade program to ensure that appropriate incentives are being provided for increased use of efficient combined heat and power.

I-95. Comment: The details of how any compensation will be administered appears to be left up to the CPUC and POU governing boards. How auction proceeds are allocated could distort the market and skew choices away from installing efficient CHP to instead purchase electricity from the grid. We suggest that treating CHP facilities the same as other deliverers for allocation purposes could result in CHP facilities being economically disadvantaged if their role as a self-provider is not also accounted for. We believe that CHP facilities act essentially as their own retail provider. Consequently, the distribution of auction revenues to retail providers in proportion to the loads they serve without a comparable distribution of auction revenues to CHP facilities would treat CHP inequitably, and that this inequitable treatment would reduce the economic incentives for installing CHP facilities. We ask ARB to reconsider the joint recommendation of the CPUC and CEC on this issue. The Joint Commissions stated, "We recommend that, for CHP facilities that meet a minimum size requirement, all CHP-generated electricity that is consumed in California, whether delivered to the grid or used on-site, receive allowances on the same basis as other deliverers, and that CHP-generated electricity used onsite receive allowances on the same basis that they are distributed to retail providers." (CACC)

> **Response:** We agree that the use of value given to electric utilities will, to a large extent, depend on decisions of the CPUC and POU governing boards. We are working closely with our sister agencies and the POUs to ensure that EITEs are property compensated. However, we do not expect allowance or allowance value to be passed from utilities to CHP facilities, because CHP facilities should pass through carbon costs to their customers. Furthermore, we have coordinated closely with the CPUC and parties involved in its QF settlement process to ensure that incentives continue to exist to develop new CHP and make existing CHP more efficient.
>
> The Joint Commission's recommendation was made before we chose a primarily product benchmark-based approach to allocation. The Joint Commissions' recommendation to treat CHP as a "retail provider" would not be appropriate, given the needs of both the electricity industry and the industrial emitters covered by this regulation.
>
> We agree that there are similarities between CHP facilities and electrical distribution utilities but we do not employ the term "retail provider." CHP facilities that sell to directly to EITEs are not regulated by the CPUC. The CPUC's role in regulating the disposition of allowance value for ratepayer benefit consistent with the goals of AB 32 could not practically be duplicated for CHP facilities; hence, we do not recommend treating CHP facilities the same as electrical distribution utilities.
>
> While the treatment of indirect emissions from electricity (electricity purchased by an EITE) in the benchmarking process is not the same for indirect emissions as for emissions from self-generation, it cannot be made completely equitable until we are assured that all purchased electricity properly incorporates a carbon cost. We note that EITE's purchasing utility electricity is a much greater portion of total purchased electricity than electricity purchased directly from CHP facilities.

I-96. (multiple comments)
Comment: The proposed allowance allocation methodology for combined heat and power (CHP) facilities creates inconsistent treatment of onsite versus offsite facilities, effectively discouraging the purchase of steam and electricity from offsite CHP facilities, and, as such, provides incentives that are contrary to the goal of reducing GHG emissions by encouraging efficient, low-carbon energy production. An independent offsite CHP facility that transfers thermal energy and electricity across its fence line to

an adjacent industrial facility will receive no allowance allocations, whereas an identical onsite CHP owned by an industrial covered entity will receive thermal and electrical allowance allocations. The program should provide equivalent incentives for both offsite and onsite CHP systems. Therefore, the regulation should be amended to provide allowance allocations to offsite CHP/cogeneration facilities, as it currently does for onsite CHP systems, based on the quantity of thermal and electrical power provided directly to industrial covered entities. This equivalent treatment should be afforded to entities regardless of the ownership structure—treating leased assets the same as wholly owned assets. (APC)

Comment: The cap-and-trade program may also disrupt existing commercial arrangements for the use of CHP at industrial facilities. If a CHP facility sells thermal energy to an industrial facility that is eligible for a direct allowance allocation under section 95890(a), the industrial facility may choose to discontinue its purchase of thermal energy from the CHP facility. This could occur because thermal energy from the CHP facility would have been subject to the cost of a compliance obligation to purchase emissions allowances, whereas thermal energy produced by the industrial facility would be eligible for direct allocation. Consequently, thermal energy from the CHP would carry an incremental GHG compliance cost and could be more expensive than thermal energy produced by the industrial facility, resulting in the unintended consequence of reducing use of CHP.

To avoid this counterproductive result, emissions associated with CHP facilities should be characterized as industrial sector emissions. CHP facilities should be eligible for allowances allocated for “industry assistance” and should be included in Table 8-1. CHP facilities should receive allowances based on the Thermal Energy Based Allocation Calculation Methodology, which would effectively allocate allowances to a source based on a thermal efficiency benchmark (0.05307 GHG allowances / MMBtu). Facilities that beat the efficiency benchmark should be able to sell the surplus emissions allowances in the quarterly auctions (or bank for use in subsequent periods) and, in doing so, CARB would create an investment incentive for repowering and efficiency improvements at existing industrial CHP facilities. (PRAXAIR)

> **Response:** We expect that there will be consistent treatment of CHP, whether it is onsite or offsite, once utility rates reflect the carbon price. Furthermore, CHP will either be compensated because it is part of an EITE facility, or it will be compensated by passing through the carbon costs to a steam or power purchaser.

I-97. Comment: As the regulation bases allowance allocation for exported power from CHP on an assumption of carbon price cost recovery, the regulation must put in place provisions to monitor and ensure cost recovery. CARB should provide (specific) language in the Cap and trade regulation (to) substantially increase investors’ confidence in new or expanded CHP economics and increase the likelihood of new development—consistent with the CHP goals contained in the Scoping Plan. Without proper incentives, a CHP facility and its thermal host are disadvantaged because they take on additional GHG emissions obligations for power produced on-site that otherwise would be the obligation of the utility. The regulation's allowance distribution scheme for CHP must be designed to ensure that the infrastructure required to promote the addition of 4,000 MW of new CHP exists. (BP)

> **Response:** Stand-alone CHP facilities will need to pass through the carbon costs to the purchasers of their thermal and electricity products. We do not believe that the regulation should interfere in CHP facilities' ability to negotiate prices in the markets for electricity and steam. (See also our responses regarding CHP facilities that may be selling electricity under long-term contracts without provisions to pass through carbon costs.) Investor confidence depends on too many variables out of the control of ARB for cap-and-trade to be able to substantially increase investor confidence. We believe that the QF settlement between CHP and cogeneration operators and the utilities has greatly improved the conditions and economics for CHP development. We will continue to work with CPUC and stakeholders to ensure that this regulation creates no disincentives and creates the proper incentives for production of electricity and thermal energy in ways that minimize emissions while maximizing other CHP benefits.

I-98. (multiple comments)
Comment: CARB should monitor market prices for electricity to ensure adequate carbon cost recovery for combined heat and power facilities. CARB's Scoping Plan recognizes CHP as a specific measure in reducing GHG emissions. One potential disincentive to optimally efficient CHP development lies in the larger carbon footprint such development imposes on the industrial facility. Installing CHP increases the emissions responsibility of the facility because it requires coverage of the export emissions. But for the exports, the facility's obligation would be limited to thermal emissions from a boiler. Consequently, to invite development there must be some assurance that a facility exporting CHP power will be able to recover its carbon costs in the market. California regulators universally seem to have taken the position that recovery of carbon costs in the market price of electricity is a theoretical "given." Developers, however, and particularly industrial facilities whose core business is not electricity generation, might not be willing to bet their capital on market theory alone. Consequently, CARB should take action to ensure that CHP export power can recover its power costs in the market. Specifically, CARB should provide the following language in the ISOR rationale for section 95891(a) and (c):

> While allowances will not be allocated to industrial cogeneration to cover emissions associated with electricity exports to the grid, this limitation is based on the assumption that these entities will be able to fully recover their costs in the market.

In addition, the final regulations should provide the following language as section 95891(d):

To ensure that industry assistance through allowance allocations meets the objectives of maintaining competitiveness and avoiding leakage, the Executive Director shall annually review electricity market prices to examine the extent to which these prices permit full carbon cost recovery for efficient cogeneration facilities serving industrial facilities. If the prices do not permit full carbon cost recovery, the Executive Director shall take action to ensure full recovery following consultation with the Public Utilities Commission.

Placing this language in the Cap and trade regulation will substantially increase investors' confidence in new or expanded CHP economics and increase the likelihood of new development. (EPUC)

Comment: Existing CHP is threatened and further CHP development in California is discouraged unless CARB addresses the disincentive that exists for the larger on-site carbon footprint that comes with production of power at an industrial facility. But for the on-site power production, the facility's emission allowance obligation would be limited to thermal emissions such as those from a (potentially less efficient) boiler. As a result, an industrial facility producing and exporting CHP power must have certainty in its ability to recover this additional carbon cost in the market. California regulators universally seem to have taken the position that recovery of carbon costs in the market price of electricity is a theoretical "given." However, industrial facilities whose core business is not electricity generation will not make or maintain capital investments in CHP on market theory alone. CARB must take action to ensure that CHP can recover its carbon costs for power generation in the market price of electricity. In addition, the final regulations should provide the following language as section 95891(d):

To ensure that industry assistance through allowance allocations meets the objectives of maintaining competitiveness and avoiding leakage, the Executive Director shall annually review electricity market prices to examine the extent to which these prices permit full carbon cost recovery for efficient cogeneration facilities serving industrial facilities. If the prices do not permit full carbon cost recovery, the Executive Director shall take action to ensure full recovery following consultation with the Public Utilities Commission.

Placing this language in the Cap and trade regulation will substantially increase investors' confidence in new or expanded CHP economics and increase the likelihood of new development, which is consistent with the CHP goals contained in the Scoping Plan. (BP)

Response: We do not agree that this regulation creates a disincentive for industrial facilities that produce power. Allowances are required for on-site CHP emissions just as they are for emissions from stand-alone CHP facilities. If an industrial facility also exports power, then the exported power has not been included in the calculations that determine the benchmark. Instead, we expect the industrial facility to pass through the cost of allowances to utility purchasers and other purchasers. As noted, the QF Settlement was made in large part to provide better incentives for the continuation, expansion, and new development of efficient CHP to meet the Scoping Plan target. We will continue to work with the energy agencies to ensure that increased effective and efficient CHP is economically viable.

While we did not add the language suggested by the commenter, we modified the product output-based allocation calculation methodology (section 95891(b)) to include a true-up to account for output not properly accounted for in previous years. This will help to maintain competiveness and avoid leakage. We will also continue to monitor the electricity market and the ability of EITEs to recover the appropriate level of carbon costs in the price of electricity sold.

I-99. Comment: CARB should provide the following language in the ISOR rationale for sections 95891(a) and (c):

While allowances will not be allocated to industrial cogeneration to cover emissions associated with electricity exports to the grid, this limitation is based on the assumption that these entities will be able to fully recover their costs in the market. (BP)

Response: No response needed. The regulatory process requires no changes to the Staff Report; this Final Statement of Reasons addresses comments.

Imported Electricity to EITEs

I-100. (multiple comments)
Comment: Finally, operation of a cogeneration or self-generation plant, and decisions about additional capital expenditures to repower or enhance its efficiency, turn in part on the relative cost of operation and value of electric and thermal energy produced compared to the forecasted costs for separate electric commodity purchases from the grid and thermal energy production. If the electric distribution utilities receive free allocations that will result in a transfer of value back to customers taking electricity from the grid, but no similar value is rebated to the loads served by on-site cogeneration or self-generation, then the cost comparison will skew against use of or investment in cogeneration or self-generation. This would be inconsistent with CARB's goals to increase use of cogeneration and self-generation as a GHG emission reduction strategy. (PRAXAIR)

Comment: In various sections of the ISOR it is implied that the electricity produced by a CHP facility that is sold to an IOU or into the grid, will be governed by the same rules that will apply to independent generators competing in the electricity sector. Specifically, cogenerators will need to purchase allowances at auction for their emissions associated with the exported electricity. On October 8, 2010, the CHP Program Settlement Agreement was filed at the CPUC and an expedited schedule was adopted with the goal of securing a Commission Decision before the end of 2010. The new Short Run Avoided Cost (SRAC) energy pricing structure that will be implemented through the settlement, allows that in the event of a GHG cap and trade program in California, the energy price will be subject to a GHG Floor Test as described in section 10.2.2 of the Settlement. In this test, the energy price will be the higher of two formulas provided in this section. One of the formulas includes recovery of the GHG Allowance price up to a set heat rate for a specified calendar year. Consequently, it was envisaged in the settlement process that while the market should reflect the cost of allowances purchased by generators at auction, a GHG floor test would be available in the first compliance period to ensure a mechanism to recover the cost of carbon for those qualifying facility (QF) contracts that pre-date the mid-2000s. After the first compliance period the SRAC energy price will be at "market" and presumably the full cost of allowances will be in the market. While this seems to be a universally accepted notion, it would seem prudent for some mechanism to be put in place to regularly monitor electricity market prices to examine whether the prices permit full recovery of carbon costs for efficient cogeneration facilities. ARB appears to suggest in the ISOR, specifically in Figure J-5, that ARB will not provide an allocation of allowances to cover CHP emissions associated with exported power to a utility or to the market. This implication should be made explicit in the cap and trade regulation. (CACC)

> **Response:** Loads served by electricity generated onsite are typically the loads of an EITE that operates a production facility as well as the on-site generation. The EITE is compensated with allowances through the benchmark methodology on a per-product basis. Therefore, there is no skewing against investment in cogeneration or self-generation once the price of all purchased electricity includes an appropriate carbon cost. We fully expect utilities to pass through appropriate carbon costs in rates to EITEs to whom they sell electricity. We believe that efficient cogeneration facilities selling power and/or steam will be able to recover their carbon costs in the markets for power and steam.

No Allocation for EITE's "Exported" Electricity or Thermal Energy

I-101. Comment: Consistent with the ISOR, the regulations should clarify that CARB contemplates no allowance allocation for power exported by EITE facility CHP. A CHP policy settlement was filed before the CPUC on October 18, 2010, and is currently pending approval. Provisions of the settlement require clarification from CARB that none of the allowances allocated to EITE entities that own exporting CHP generation are intended to cover carbon costs associated with exports. The settlement provides that free allocation of allowances to cover carbon compliance costs associated with exported electricity can decrease a CHP facility's short-run marginal cost (SRAC) energy payments. The settlement on page 67-68 provides a formula for allocating free allowances between on-site use and exported power in the event that CARB or another agency fails to make clear the purpose of a free allowance allocation:

(ii) If CARB (or any other Governmental Authority) does not allocate Free Allowances received by Seller as described in subsection (i) above, then Seller shall set forth in the Free Allowance Notice the quantity of Free Allowances allocated to the energy

generated by the Generating Facility and delivered to Buyer during the applicable time period (FAd) utilizing the following formula:

*FAd = FAt * (Ge/(Ge+ Gt)) * (Ed/(Esh + Ed))*

Implicit in the regulations and ISOR is the notion that any free allowance allocation is provided only for CHP power used by the industrial host. The ISOR and accompanying appendices suggest that CARB would not provide an allocation of allowances to cover industrial CHP emissions associated with exported power, but this clarification is not reflected in the draft regulations. Importantly, Table J-7 provides that an industrial facility would be allocated allowances to cover emissions associated with heat consumed and electricity generated and used on-site. Not stated is CARB's expectation that industrial CHP must recover GHG compliance costs associated with exported power from the market. Failure to clarify this point in the Final Statement of Reasons and regulation could leave industrial CHP exposed to significant compliance costs, moving free allowances from the industrial to the utility side of the ledger. This would in turn, compromise the contemplated levels of industry assistance noted in Table 8-1 of Subarticle 8, which indicates that from 2012-2014, all industrial facilities, regardless of leakage risk, would receive 100 percent industry assistance.

To address this significant gap in the proposed regulations, the following language must be added to the following sections of section 95891:

> Section 95891(a):
>
> *"A_t" is the amount of California GHG allowances directly allocated to the operator of an industrial facility for all activities with a product output-based allocation from budget year "t."* <u>This allocation shall exclude GHG compliance costs associated with electricity generated by the facility and exported to an interconnected utility.</u>
>
> Section 95891(c):
>
> *"A_t" is the amount of California GHG allowances directly allocated to the operator of an industrial facility with a thermal energy-based allocation from budget year "t."* <u>This allocation shall exclude GHG compliance costs associated with electricity generated by the facility and exported to an interconnected utility.</u>

CARB should also consider modifications to the regulations to clarify how the treatment of exported power may impact the allowance allocation to the EITE host. (EPUC)

> **Response:** We did not add the language recommended by EPUC. However, we modified sections 95891(b) and (c) to clarify the benchmarking methodology. Neither of these sections allocate allowances explicitly to cover GHG compliance costs associated with electricity sold or "exported" by an industrial facility in the benchmarks that determine allocations to energy-intensive trade-exposed industrial facilities. In this way CHP is treated in a consistent fashion to all other

power generators selling into power markets. It is true that we expect industrial facilities to attempt to pass through as much of their GHG compliance costs as the markets for electricity and thermal energy will accept.

Allocation of New or Increased CHP

I-102. (multiple comments)
Comment: Regulations should ensure parity in allowance allocations for new or expanded reliance on CHP. Providing allowances to encourage incremental reliance on CHP will promote the Scoping Plan. Section 95853(e) provides free allowances to a new entrant in the first year following the year in which its emissions exceed the threshold in section 95812. It further provides that the allowance allocation in the first qualifying year will be "*twice the number calculated pursuant to section 95891.*" This provision should clarify that this treatment applies not only to new entrants, but that industrial facilities' increasing reliance on CHP will receive allowances in parity with other similarly-situated, existing facilities. Modify section 95853 as follows:

> *For a new entrant that is eligible to receive free allowances pursuant to subarticles 8 and 9, the first year for this entity to receive free allowances is the year ….The number of free allowances for this new entrant to receive in that year is twice the number calculated pursuant to section 95891. <u>For purposes of this provision, "new entrant" includes an existing facility that increases its reliance on cogeneration.</u>* (EPUC)

Comment: CARB should clarify that investment in new CHP or expanded reliance on CHP will benefit from the free allowances designated for new entrants in section 95853(e) in an amount that ensures parity with other similarly-situated EITE entities. (EPUC)

Comment: Transition of CHP ownership is another issue that will need to be addressed in the solution for third-party energy suppliers with existing contracts. For example, what happens if, at an EITE industrial site, the CHP facility is owned by a third party in 2012, but in 2014 it is purchased by the industrial host? If the industrial host did not emit enough emissions to be a "Covered Entity" or an "Opt-in Facility" in 2012, what happens in 2014 when the industrial host purchases the CHP facility and is suddenly responsible for the GHG emissions compliance costs associated with the CHP facility? Will the ARB provide an allocation of free allowances? The preferred solution for this issue will likely depend on the solution implemented for allowance allocation for third-party legacy contracts. (CACC)

> **Response:** For new entrants and for existing facilities that increase operations, free allocation for the purpose of leakage minimization is always aimed at encouraging efficient production. We prefer the allocation to be based on production levels wherever possible. If a facility that receives allocation based on the product-based allocation methodology increases its production capacity and also increases its reliance on CHP, its allocation will increase based on

increased production of the benchmark product, but will not be impacted by its increased onsite consumption of CHP electricity or thermal energy. We are willing to work with all industries to develop additional product benchmarks if necessary. If a facility that receives allocation based on the energy-based allocation methodology increases its reliance on CHP through a change in ownership, the allowances initially allocated for purchased steam would cover a large portion of the CHP carbon costs.

Contracts with No Pass-Through

I-103. (multiple comments)
Comment: The proposed regulation makes no allocation for generators subject to long-term contracts that do not allow for recovery of the costs associated with purchasing allowances. Nor does it otherwise provide transitional assistance to such generators until such time as their existing contracts expire or are substantively amended.

Further, while the California Public Utilities Commission's (CPUC) proposed qualifying facility (QF) settlement would allow combined heat and power (CHP) generators to recover costs associated with purchasing allowances for generation of power sold to the grid, the QF settlement does not address the allowance costs such generators will bear as a result of their obligation to provide steam and electricity to industrial consumers pursuant to long-term contracts that provide no mechanism for recovery of allowance costs. The problem affects not only generators selling power to IOUs and POUs, but also those who are selling electricity and/or useful thermal energy to nearby or collocated industrial operations under long-term contracts. These CHP or cogeneration facilities represent a highly efficient, environmentally preferable alternative to meeting industry's energy needs. For this reason, CARB has made expansion of CHP a significant component of its overall Scoping Plan, which targets an increase of 4,000 MW of installed CHP capacity within the State by 2020. This measure is intended to displace approximately 30,000 gigawatt-hours (GWh) of demand from other power generation sources, resulting in a targeted reduction of 6.7 million metric tons of CO_2e in 2020. However, without providing transitional assistance for generators subject to long-term contacts that do not allow for recovery of costs associated with purchasing allowances, the continued viability of many existing CHP generators will be seriously threatened.

Further, the CPUC's proposed QF settlement does not address the potentially serious economic consequences to CHP generators subject to long-term contracts that do not provide a mechanism for recovery of allowance costs associated with generation of electricity and steam sold to their industrial customers. Because of the importance of existing CHP facilities to assuring a highly efficient source of power and useful thermal energy for industry in California, CARB must provide transitional assistance to CHP owners subject to long-term contracts that do not provide a mechanism for recovery of GHG compliance costs. Where a covered entity or opt-in covered entity would receive a direct allocation for industry assistance under the Proposed Regulation, but that entity purchases power and/or steam from a CHP generator pursuant to a contact that provides for no recovery of allowance costs, Calpine believes that allowances attributable to the purchased power and steam should be provided to the long-term contract generator, and not the industrial host, since the industrial host would not in those circumstances experience an increase in costs associated with its purchase of such power and steam.

Calpine would propose that CARB publish a revision to the proposed regulation that provides for a direct allocation of emissions allowances to generators subject to long-term contracts that provide no mechanism for recovery of allowance costs. The proposed revisions would merely provide transitional assistance until such time as the existing contract expires or is substantively amended. Under the proposed revisions, CARB would provide allowances to qualifying long-term contract generators based upon their historic emissions, as established in their most recent verified emissions report submitted to CARB pursuant to the MRR. For conventional generators, the allocation would come from the 89 million metric tons CO_2e of allowances allocated to the load-serving entities for the 2012 budget. For cogeneration facilities, the allocation would come from the approximately 11 million metric tons CO_2e of emissions from cogeneration facilities, which the ISOR acknowledges have not been included within the 89 million tons allocated to the load serving entities, but have yet to be apportioned. This allocation to long-term contract generators would then be subject to an annual "true-up" based upon actual reported emissions for the year in which an allocation is made. No entity awarded allowances under this provision would be able to sell, transfer or otherwise use such allowances, except to meet their annual and triennial compliance obligations. Nor would they be allowed to bank such allowances for future use; any surplus allowances would be returned to the Allowance Price Containment Reserve after each annual true-up. To accomplish these changes, Calpine proposes the following revisions to the proposed regulation, which are largely based upon the provisions concerning long-term contract generators appearing within proposed federal climate change legislation and regulations implementing RGGI. Modify sections 95802, 95870, 95890, and 95894 as follows:

> 95802(a)(111) "Long Term Contract" means a sales or tolling agreement governing the sale of electricity and/or useful thermal energy from an electric generating facility or cogeneration facility at a price (whether a fixed price or price formula) that does not allow for recovery of the costs of compliance with this regulation and that is at least five (5) years in duration, provided that such agreements are not between entities that were affiliates of one another at the time at which the agreement(s) were entered into.
> (a)(112) "Long-Term Contract Generator" means a covered entity which is not an electric distribution utility and which operates an electric generating facility or cogeneration facility pursuant to one or more long-term contracts.
>
> 95870(a) Allowance Price Containment Reserve. On December 15, 2011, the Executive Officer shall transfer allowances to the Allowance Price Containment Reserve, as follows:

(c) Allocation to Public Utilities.

(1) Electrical Distribution Utilities. The Executive Officer will place an annual individual allocation in the holding account of each eligible distribution utility on or before January 15 of each calendar year from 2012-2020 pursuant to section 95892. Allowances available for allocation to electrical distribution utilities shall be 89 million multiplied by the cap adjustment factor in Table 9.2 for each budget year 2012-2020 ~~2020, less the amount of allowances for that year that are allocated to long-term contract generators pursuant to section 95894(a)~~

95890(d) Eligibility for Long-Term Contract Generators. A long-term contract generator that has demonstrated its eligibility to the satisfaction of the Executive Officer pursuant to section 95894 of the regulation shall be eligible for direct allocation of California GHG allowances if it has complied with the requirements of the MRR and has obtained a positive or qualified verification statement for the prior year pursuant to the MRR. The owner of a facility shall cease to be eligible to receive emissions allowances under this subsection upon the earliest of the definition of a long-term contract generator or the requirements of this paragraph.

95894(a) Direct Allocation to Long-Term Contract Generators. Not later than February 1, 2012, and each calendar year thereafter, the Executive Officer shall deposit in the compliance account of the owner or operator of each eligible long-term contract generator a quantity of emission allowances of the same vintage year that is equal to the average number of tons of greenhouse gas emitted as a result of sales pursuant to long-term contracts during the three preceding calendar years. Any allowances received by a covered entity pursuant to this paragraph shall remain within such entity's compliance account and shall not be transferred or sold to any other party or used for any other purposes, other than to satisfy the annual or triennial compliance obligation of the covered entity.
(b) Demonstration of Eligibility. To be eligible to receive a direct allocation of allowances under this section, an authorized representative of a long-term contract generator shall submit each of the following in writing to the Executive Officer no later than September 30 of the year preceding the calendar year for which it is seeking an allocation:

(1) A copy of any long-term contracts for which it is seeking an allocation;
(2) A statement certifying that each such long-term contract does not allow the covered entity to recover the cost of GHG allowances from the counterparty purchasing electricity and/or useful thermal energy from the facility;
(3) A statement that the long-term contract was originally executed prior to January 1, 2007, remains in effect and has not been amended since the effective date of this regulation to change the terms governing the price or amount of electricity or useful thermal energy sold or the expiration date;
(4) A statement of the covered entity's total GHG emissions reported pursuant to the MRR for the three preceding calendar years;

(5) A statement of the covered entity's GHG emissions during the three preceding calendar years resulting from sales of electricity and/or useful thermal energy pursuant to qualifying long-term contracts; and

(6) The following certification statement by the authorized account representative or any alternative authorized account representative: "I am authorized to make this submission on behalf of the long-term contract generator requesting allowances. I certify under penalty of law that I have personally examined, and am familiar with the statements and information submitted with this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining this information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I consent to the jurisdiction of California and its courts for purposes of enforcement of the laws, rules, and regulations pertaining to title 17, article 5, sections 95800 et seq., and I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

If, subsequent to the submittal of the foregoing information and supporting documentation, there is any material change in the information and statements provided to the Executive Officer, the persons who submitted such information and statements shall submit a supplemental certification and supporting material addressing any such material change within 30 days after the change occurs. For purposes of this paragraph, a long-term contract shall be deemed to be originally executed prior to January 1, 2007 if it was originally executed prior to such date, but was subsequently amended and restated prior to the effective date of this regulation due to the bankruptcy or reorganization of the long-term contract generator or its parent company or affiliate.

(c) Determination of Eligibility. Upon receipt of the information required by paragraph (b) of this section, the Executive Officer shall determine whether the party submitting such information has demonstrated that it is eligible to receive a direct allocation of allowances pursuant to this section and shall notify that party of his other determination by January 30 of the calendar year for which the allocation is sought.

(d) Annual True-Up Obligation. By March 1 of the year following the calendar year for which allowances have been provided pursuant to this section, the long-term contract generator shall submit a report to the Executive Officer stating the actual emissions of GHG resulting from a sales of electricity and/or useful thermal energy pursuant to qualifying long-term contracts during the preceding calendar year.

(1) Distribution of Surplus Allowances to Long-Term Contract Generators with a Shortfall. If the amount of allowances previously allocated by the Executive Officer to a long-term contract generator for any given calendar year exceeds the long-term contract generator's actual emissions resulting from the sales of electricity and/or useful thermal energy pursuant to qualifying long-term contracts during such calendar year, the Executive

Officer shall deduct the surplus allowances from the long-term contract generator's compliance account and shall then distribute them to long-term contract generators that reported a shortfall in the amount of allowances previously allocated to them for a given calendar year, in comparison to their actual emissions resulting from the sale of electricity and/or useful thermal energy pursuant to qualifying long-term contracts during such calendar year.

(A) If the amount of surplus allowances available for distribution for a given calendar year is less than the shortfall reported by all long-term contact generators for the same calendar year, the Executive Officer, shall distribute an equal percentage of the surplus allowances to each long-term contract generator that experienced a shortfall, with the numerator equal to the total amount of surplus allowances to be distributed and the denominator equivalent to the total shortfall experienced by all long-term contact generators for such calendar year. For example, if the total number of surplus allowances available for distribution pursuant to this paragraph is 100,00 metric tons of CO_2e and the total shortfall claimed by five long-term contract generators is 200,00 metric tons of CO_2e, then each of the five long-term contract generators would receive allowances in an amount equivalent to 50 percent of its respective shortfall.

(B) If the amount of surplus allowances available for distribution for a given calendar year is greater than the shortfall reported by all long-term contract generators for such calendar year, the Executive Officer shall transfer the remaining portion of surplus allowances to the Allowance Price Containment Reserve administered pursuant to section 95913 of this regulation.

(2) The requirements of this paragraph shall not change the date when a covered entity's reporting obligation is due under MRR.

As an alternative to a direct allocation to the long-term contract generators, the proposed regulation could be revised to require that the electric distribution utilities set aside a portion of the allowances allocated to them pursuant to section 95892 to meet the compliance obligation for all power purchased pursuant to long-term contracts. The electric distribution utilities would then be required to transfer the necessary allowances to the long-term contract generators' compliance accounts within 30 days of the relevant surrender date for the annual and triennial compliance obligations. Under this approach, the allowances attributed to CHP generators' sale of power and steam to industrial hosts could also be drawn from the pool of allowances allocated to the load serving entities, assuming that CARB added to that pool the approximately 11 million metric tons of emissions attributable to cogeneration, which are not reflected by the load serving entities' current allocation of 89 million metric tons CO_2e for 2012. (CALPINE1, CALPINE2

Comment: The issue of existing contracts for third-party thermal energy supply and electricity supply (collectively referred to as “energy supply”) does not appear to have been fully contemplated in the proposed cap-and-trade regulation. Figure J-5 indicates that Heat Sold and Electricity Sold will have “Full Carbon Cost Pass-Through”, but qualifies these statements by “assuming no existing contract issues.” For the CHP sector, this assumption is more likely to be the exception rather than the rule. The majority of CHP contracts were executed with industrial hosts prior to the passage of AB 32 and do not contain provisions for carbon cost pass-through. Natural gas-fired CHP facilities are inherently energy intensive. CHP facilities that can pass through carbon costs are not trade exposed, but those facilities with existing contracts that do not allow any carbon cost pass-through are arguably more trade exposed than any other industry in California. Unlike other energy intensive trade exposed (EITI) sectors, third-party CHP facilities with existing contracts are not eligible for any allowance allocation. The cap-and-trade program needs to have some mechanism to address this issue. The concern about legacy contracts may be a transition issue. When the commercial agreement between parties expires, any new agreement could include carbon cost recovery provisions. (CACC)

> **Response:** We believe that the best way to solve problems with contracts that do not include specific provisions for addressing carbon costs is to amend the contracts. In this response, we focus on issues regarding long-term contracts for electricity, and we consider contracts for steam in the next response. We are aware of a potential inequity if generators, be they CHP facilities or other electricity generators, cannot pass through carbon costs to purchasers. Stakeholders that are party to contracts for which there are no cost pass-through provisions approached ARB prior to the release of the proposed cap-and-trade regulation. ARB staff collaborated with industry to develop a survey to assess the magnitude of the issue. Staff received information from stakeholders representing over 50 generation facilities. In addition, many stakeholders have informally discussed their long-term contract issues with staff. Most of the long-term contract issues concern CHP facilities, while a smaller number involve electricity generators that do not also provide useful thermal energy. In this response, we consider long-term contract issues for CHP facilities; other long-term contract issues are covered in a separate section of response.
>
> Based on information provided by stakeholders, we have divided long-term contracts into categories based on how we expect the cost pass-through issue to be resolved. Many CHP facilities provide electricity to an IOU. CCAC, an association that represents cogeneration facilities told us informally in an email that “all 16 facilities [members of CCAC with long term contract issues] provide wholesale electric sales to an investor-owned utility, and that portion of their output is covered by the avoided cost pricing in the CHP QF settlement agreement.” The same email noted that many of these facilities sell steam or steam and electricity to an industrial host, and that the majority provide energy to EITEs. Furthermore, if there are remaining contract issues regarding sale of electricity to utilities, we believe that they can be resolved through the CPUC

proceeding addressing utility cost and revenue issues associated with greenhouse gas emissions. This process began when the CPUC issued an Order Instituting a Rulemaking in March 2011, and we understand from the CPUC that pass-through of carbon costs in long-term contracts will be addressed. We believe that this is the proper venue to resolve contract issues for electricity sold by CHP generators to IOUs.

Other CHP generators sell electricity to EITEs. Some of the contracts commenced or were amended after AB 32 became law. We believe that facilities that negotiated these contracts had the opportunity to include provisions for future carbon costs, and no action by ARB is needed.

Some stakeholders have claimed long-term contract issues for facilities that either have no compliance obligation or a very small obligation. These include some biomass facilities, which may combust a small amount of fossil fuel, and others that are below the threshold for a compliance obligation. Since these facilities have little or no compliance cost, they have no cost pass-through issues to resolve.

Other CHP facilities may be able to resolve issues by switching from high-emitting fuels such as coal or coke to lower-emitting fuels, and by renegotiating contracts with their counterparties.

We have strongly encouraged stakeholders on both sides of these contracts to renegotiate these contracts so that the sellers are not disadvantaged and costs are passed through.

There is a very wide variety of ways to account for risk in electricity contracts. Even with the information provided in response to the survey, it is not clear how issues of risk were resolved. We are encouraged by progress reported by entities that have begun the renegotiation process.

The calculation of allocation to utilities is based on assumptions of carbon cost pass-through from generating facilities. We are still considering withholding allowances from utilities that do not face carbon costs due to long-term agreements with a generator that truly prevents the generator from recovering any carbon costs. This change would require a future regulatory action.

Steam Contracts with No Pass-Through

I-104. (multiple comments)
Comment: CARB is developing protocols for combined heat and power ("CHP") facilities related to the allocation of compliance responsibility between the electric and thermal components of the CHP operations. IEP supports this initiative. However, solving the allocation of compliance responsibility between the electric and thermal components of the CHP operation will not be sufficient, because not all CHP facilities

are similarly situated. Specifically, the proposed regulation does not address the condition in which a CHP project contractually provides electrical output to the grid and, via a separate contract, it sells steam to the thermal host; and the steam contract fails to provide a reasonable means of cost recovery to the merchant generator for any GHG compliance costs that it may bear in relation to the steam production. In this situation, the CHP entity may have two separate contracts in which the electric contract OR the steam contract fails to provide a reasonable expectation of recovery of GHG costs incurred by the CHP entity. In this situation, the steam contract should be treated similarly to the electric contract (proposed above). Accordingly, the proposed regulation must be modified to provide the Executive Officer the authority to address this situation. IEP recommends that the proposed regulation should be amended to clarify that CHP entities, upon a requisite showing to CARB that they are unable to reasonably recover the costs of GHG allowances associated with their pre-existing steam contracts, will be provided directly from CARB free allowances sufficient to meet their GHG regulatory obligations associated with the production of the steam for their thermal host. Modify section 95891(a), under Allocation for Industry Assistance, as follows:

(a) The Executive Officer shall determine the amount of allowances directly allocated to each eligible covered entity or opt-in covered entity using the product output-based benchmarking allocation calculation methodology specified in subsection (b) if the entity is from the sector listed in both Table 8-1 and Table 9-1. The Executive Officer shall determine the amount of allowances directly allocated to each eligible covered entity, or opt-in covered entity using the thermal energy-based benchmarking allocation calculation methodology specified in subsection (c) if the entity is from the sector listed in Table 8-1 but not listed in Table 9-1. <u>The Executive Officer shall determine the amount of allowances directly allocated to eligible covered entities providing steam for industrial processes for which a reasonable means of cost recovery for allowances associated with the production of steam is unavailable. In making this determination, the Executive Officer shall use the thermal energy-based benchmarking allocation calculation methodology specified in (c).</u> (IEPA)

Comment: PEB has a long term steam sales agreement with UC-8 that expires in August 2017. This long term agreement has no mechanism in which to pass through any GHG costs that PEB incurs while meeting its contractual obligations to UC-8. PEB, on average, supplies the UC-8 campus with 1,050,000 MMBtu/year and any future GHG costs (that cannot be recouped by a pass through mechanism) would be economically devastating to PEB. The impact of the "Proposed Regulation to Implement the California cap-and-trade Program" (proposed regulation) on Combined Heat and Power (CHP) facilities is an issue of significant importance to PEB as we evaluate the regulatory landscape of California and consider options under the CHP Program Settlement Agreement. These options for PEB include whether to sign contract amendments adopting an energy payment calculation based on perceived exposure to GHG risk, repower the existing facilities or develop a new project on the UC-B campus. (MAZOWITA)

Comment: ARB should consider altering allowance allocation for cogeneration facilities owned by electric utilities with long-term steam sales. SMUD invested in three cogeneration facilities in the 1990's to encourage cleaner electricity generation and low-emissions industrial facilities. The plants jointly produce roughly 1,000,000 tonnes of CO_2 per year, nearly 10 percent of which is associated with steam sales made to four industrial heat hosts. Because these heat hosts are counterparties in long-term steam sales agreements with no clauses for pass-through of carbon costs associated with cap and trade regulations, SMUD feels it is important that the ARB allocate the allowances that otherwise would have been allocated to these heat hosts had they been responsible for an emissions obligation instead to the cogeneration facilities who will have the financial obligation for compliance with the cap and trade regulation for these emissions. SMUD is not able to re-open the contracts without substantial risks, and it is unlikely that the heat hosts would agree to re-opening the contracts due to lack of benefit to them as well as past difficulty in negotiating these contracts at the outset of the agreements. (SMUD1)

> **Response:** We believe that the best way to solve problems with contracts that do not include specific provisions for addressing carbon costs is to amend the contracts. Parties to contracts have many ways of handling a great variety of risks within contracts, including, for example, regulatory cost risks. We have no way of knowing what risks were taken into account when long-term contracts for steam were put in place.
>
> In addition to questions about what risks were considered, there are questions about how hard or easy it would be to renegotiate a contract to allow pass-through of some or all of the carbon costs.
>
> With reference to the comments above from CACC, Calpine, and IEPA, we note that many of these contracts are between oilfield cogeneration facilities and petroleum producers, frequently providing thermal energy that is used primarily for enhanced oil recovery. In many cases, the purchaser of the steam is an EITE in the crude petroleum and natural gas extraction industry, or the natural gas liquid extraction industry. The thermal energy provider may be the only available source of the thermal energy and may be in a strong position to renegotiate. Furthermore, in some cases, the CHP facility providing thermal energy is a subsidiary of a covered EITE in the oil and gas industry. In these cases, the owner of the parent firm is allocated allowances under the regulation, even if the CHP facility per se is not.
>
> We did not modify the regulation as requested by IEP because such a one-size-fits-all would not be appropriate for many situations. It would be very difficult, if not impossible, for the Executive Officer of ARB to determine what kind of risk trade-offs were made internally by either party to a long-term steam contract.
>
> It appears that one option is to sign contract amendments adopting an energy payment calculation that includes GHG risk. We recommend proceeding with

that option where acceptable to both counterparties. Alternatively, repowering or developing a new project could potentially reduce GHG emissions while also occasioning a new contract.

If SMUD's steam hosts qualify as EITEs they may be eligible for allowance allocation. It appears from the comment that SMUD has not yet asked the steam hosts to consider reopening the contracts, as recommended by ARB to all stakeholders with long-term contact issues. The counterparties may also face risks if contracts are re-opened.

Allocation for leakage prevention and transition assistance is based on an assumption of purchased steam creating a carbon cost. We are still considering withholding allowances from EITEs that do not face carbon costs in cases where long-term contracts prevent thermal energy sellers from recovering these costs. This change would require a future regulatory action.

Threshold-Incentive

I-105. Comment: A commercial/industrial customer should not be bumped over the cap-and-trade threshold of 25,000 $MTCO_2e$ because of clean Onsite CHP. A 4–5 MW CHP system can trigger the 25,000 $MTCO_2e$ threshold even if there are no other GHG emission sources onsite. As most sites will already have some level of natural gas use, the threshold could be reached with CHP systems much smaller than 4 MW. Cap-and-trade has a negative stigma associated with it which will affect the CHP decision process for commercial/industrial customers facing Cap and Trade compliance only if they install CHP. In addition to the perception that CARB is looking at CHP as a carbon emitter, other customer deterrents regarding Cap and Trade include the cost and complexity of obtaining carbon allowances and the extra scrutiny, monitoring and reporting that will be required. We strongly recommend that customers facing Cap and Trade because of CHP be exempted. (CACDGC)

Response: Most commercial/industrial customers below the threshold have GHG emissions primarily from natural gas. When delivered natural gas is covered starting in 2015, and carbon costs are passed through from natural gas and electric utilities to commercial/industrial users, these users will face carbon costs on all direct and indirect emissions. Few CHP systems from 4-5 MW have been built or are currently planned. Commercial and industrial facilities will benefit from installing efficient CHP and lowering their total carbon footprint by the time most of these systems can be planned and built. We encourage this action.

Other

I-106. Comment: Another issue related to third-party energy supply is the requirement to be a covered entity in order to receive an allowance allocation. Table J-75 states that facilities will receive a direct allocation of allowances for thermal energy imported from off-site. But, in order to be eligible for any allocation of allowances, a facility must be a covered entity or an opt-in covered entity. This means the facility must report at least 10,000 metric tons of CO_2e to qualify to opt-in. Consequently, a facility that purchases the majority of its thermal energy from a third-party will have very high indirect emissions, but no direct emissions, and may have an incentive to increase direct emissions in order to become a covered entity and be eligible for an allowance allocation related to off-site thermal supply. (CACC)

> **Response:** This comment is highly speculative. It is not true that a facility must report 10,000 metric tons to opt in. We believe that it is likely that a facility that imports very large amounts of thermal energy is already covered under the 25,000 $MTCO_2e$ threshold. If indirect emissions are properly priced, the incentive for efficient energy supply will be correct.

General

I-107. Comment: In reviewing the ISOR it is clear that the development of product based benchmarking and the identification of output metrics to establish benchmarks is at varying stages of development, depending upon the industrial sector. For those industrial entities where CHP is an integrated part of the process and will be subject to product based benchmarking, there is some confusion as to how the energy (both thermal and electric) and associated emissions will be incorporated into the product based and energy use benchmarks. We anticipate that if the proposed regulation is adopted in December, work will continue into 2011 to finalize the benchmarking design. Members operating in specific industrial sectors would like to provide input to that process. (CACC)

> **Response:** No response needed.

I-108. Comment: Despite the fact that CARB identified increased deployment of CHP as an important mitigation measure in its AB 32 Scoping Plan, the proposed Cap and trade program effectively penalizes some early adopters of CHP. The proposed cap-and- trade program will both penalize the University for early action, and will curtail the University's ability to invest in projects that directly reduce its greenhouse gas emissions. The University is regulated under cap-and-trade largely because it operates five large combined heat and power (CHP) plants. But for these CHP plants, several UC campuses would likely fall below CARB's cap and trade compliance threshold until 2015. CHP is just one of the investments that the University has made to meet its commitment to mitigate its own greenhouse gas emissions. The University adopted a policy goal of reducing emissions to 2000 levels by 2014, and to 1990 levels by 2020. To meet its ambitious GHG emission reduction targets, the University has made substantial investments in onsite renewable energy generation and has an aggressive energy efficiency program through which it is spending approximately $250 million on energy reduction projects over a three-year period ending in 2012, and plans for additional energy reduction and renewable energy projects after 2012. To comply with CARB's Cap and Trade program, the University will have to use its limited state-allocated funds to purchase allowances, rather than investing in projects that directly reduce greenhouse gas emissions. This problem could be corrected through an allocation of allowance value to the University, for the explicit purpose of investing in greenhouse gas mitigation projects. (UC1)

> **Response:** UC is not an EITE and does not qualify for allowances, because it is not an industry that is energy intensive or trade-exposed. UC supplies both commercial and residential load from its cogeneration. In the absence of an on-campus cogeneration unit, a UC campus would still face a carbon price for the heat it produced and the power it purchased from an electric utility (assuming an appropriate carbon price in power and gas purchased from utilities). Full carbon pricing creates both the correct incentives to reduce greenhouse gases in the future and rewards for early CHP installation that lowered the total GHG footprint of a campus. We would expect UC to pass through its carbon costs in both cases. That said, at the October 20, 2011 meeting, the Board directed staff in Resolution 11-32 to coordinate with State universities and stakeholders to evaluate options for compliance, with amendments to the regulation as appropriate, including options for the use of auction revenue and to report back to the Board in summer 2012.

I-109. Comment: Free allowances for select industrial sectors could compromise CHP if offsetting GHG emissions at the CHP site and at the central power plant are not taken into account. Industrial benchmarking for select industries should not compromise CHP implementation. Additional free allowances should be considered for CHP that recognizes the system wide benefits and not just onsite emissions. (CACDGC)

> **Response:** It is not clear what the commenter means by offsetting GHG emissions. We do not provide free allowances to CHP except indirectly when CHP is part of an EITE. Otherwise, we expect CHP to pass through carbon costs.

I-110. Comment: Facilities that self-generate electricity or make use of on-site CHP cogeneration have made significant investments in generation technology (and emissions control equipment) that have helped remove load from the grid, avoid electrical transmission losses and avoid gas transmission compression costs. The GHG emissions from these long-term investments must not create a benchmark penalty for collocated upstream oil and gas operations. There are many challenging market barriers (e.g., departing load charges, lack of contracts, and resistance from utilities) faced by CHP operators and developers that limit the State from realizing the emission reduction potential of CHP. (OPC)

> **Response:** EITE facilities that self-generate or make use of on-site CHP will receive allowances based on product or energy benchmarks. They will be able to avoid carbon costs in the price of power they would otherwise have purchased from utilities.

I-111. Comment: A key emission reduction measure is the proposed cap and trade program. Its effect on combined heat and power (CHP) is of significant interest to me. Senate Bill 412, enacted in 2009 seeks, among others, CHP technologies to be considered by the PUC to be added to the Self Generation Incentive Program. My co-authors, Senators Padilla and Blakeslee, and Assembly member Nancy Skinner, firmly believe that CHP with its superior efficiency and greenhouse gas performance compared to central station power plants in California will help our state achieve its greenhouse gas reduction goal. I believe there are several technical and public education/outreach issues that will need to be addressed after Board action on December 16, 2010. I urge staff to work closely with the CHP industry to address all remaining issues and do what is necessary and appropriate to have a robust CHP industry in the state that enables the ARB to achieve its goals for this technology sector. (SENKEHOE)

> **Response:** We agree that efficient CHP is important to help California achieve its emission-reduction goals. We have continued to work with the CHP industry to address their issues and believe that the cap-and-trade regulation will be compatible with a robust CHP industry in California; and in fact, provides incentives for efficient CHP to be developed.

I-112. Comment: Onsite CHP GHG emissions should not be compared with the average emission rate of the entire utility system as inferred in the proposed regulation. The Scoping Plan correctly benchmarks CHP against the avoided fossil generation emissions. Likewise, Cap and Trade price signals should reflect CHP's GHG impact relative to the same standard and not to the average GHG emission rate for the entire utility generation mix. Our recommendation would be to grant free allowances to Onsite CHP to properly compensate for the price signal error. (CACDGC)

> **Response:** We agree that a marginal, rather than average, emissions rate should be used when comparing the avoided emissions from displacing grid power. Carbon price signals in electricity rates should reflect the emissions rate of the marginal generator dispatched into the power markets.

I-113. Comment: The AB 32 Scoping Plan calls for the state to increase CHP energy generation by 30,000 GWh, yet the cap and trade regulation provides no incentives for development or expansion of CHP. In fact, the threat of creating a cap and trade compliance obligation is likely to discourage facilities including wastewater treatment plants from installing or expanding efficient CHP systems. We therefore encourage ARB to direct some portion of allowance value to development of a program that incentivizes CHP. (BACWACC)

> **Response:** We believe that the design of the program, and the incorporation of the price signal into the cost of electricity, will create an incentive for the development of efficient CHP. Other agency's programs provide incentives for various scales of CHP, and for renewable energy production at wastewater

treatment plans. It is not necessary to provide allowance value as requested in order to provide an incentive for cost-effective and efficient CHP.

I-114. Comment: To avoid potential conflicts associated with implementation of the qualifying facility/combined heat and power (QF/CHP) settlement pending at the California Public Utilities Commission (CPUC), CARB's regulations must explicitly state what is implicit in the draft regulation: none of the free allowances allocated to EITE entities will be provided to cover the emissions associated with those entities' power exports to the grid. (EPUC)

Response: The product output-based benchmarks do not include allocation of allowances for electricity exported by an EITE. Furthermore, the energy-based allocation methodology (modified from what was previously the thermal energy based benchmarking methodology in section 95891(c)) adjusts to exclude electric sales when calculating free allowances for EITEs.

I-115. (multiple comments)
Comment: Third, the proposed regulation is not adequate in its treatment of combined heat and power (CHP). Third party CHP's serving the refining industry should be treated as part of the refining sector with respect to electrical and thermal energy distributed to a refinery and as part of the power sector with respect to electrical energy distributed to utilities. (TESORO)

Comment: Oil refineries have pushed for subsidized cogeneration, a truly bad idea, which would replace clean energy electricity, with oil refinery-generated electricity. While industrial energy efficiency is essential, and while existing refinery processes should be required to capture waste heat, adding unneeded, expanding oil refinery electricity is directly counter to the RPS (Renewable Portfolio Standard), which is aiming at converting fossil fueled electricity into clean electricity. CARB must not allow oil refinery-generated electricity to subvert this process and take us backwards. (CBE1)

Response: We do not agree with TESORO that third-party CHPs distributed to a refinery should be treated as part of the refining sector. Rather, we expect CHPs that are not part of an EITE to pass through carbon costs. If and when a carbon price is present in all purchased power, the compensation for these carbon costs could be incorporated into the product benchmarks (or reductions in these costs created in some other fashion) to help minimize leakage. The regulation will not subsidize inefficient cogeneration, and we agree that adding inefficient electricity generated from fossil fuels is undesirable.

I-116. Comment: Cogeneration and self-generation are efficient, clean, and reliable approaches to generating power and thermal energy from a single fuel source. That is, they use heat that is otherwise discarded from conventional power generation to produce thermal energy. This energy is used to provide cooling or heating for industrial facilities, district energy systems, and commercial buildings. By recycling this waste heat, cogeneration and self-generation systems can achieve a dramatic improvement over the conventional fossil-fueled power plants, or from separate production of electricity and useful thermal energy. Cogeneration plants' higher efficiencies reduce air emissions of nitrogen oxides, sulfur dioxide, mercury, particulate matter, and carbon dioxide.

Moreover, cogeneration and self-generation facilities reduce net grid demand and associated transmission losses, a fact recognized by the Modeling GHG Reductions Strategies California Air Resources Board ENERGY 2020 Inputs and Assumptions. See page 21. Appendix N – Economic Analysis, Figure N-3, of the proposed regulation identifies cogeneration as a favored policy of the state. (PRAXAIR)

Response: No response is needed.

I-117. Comment: Allowances should be freely allocated to cogeneration facilities supporting industrial operations. As a covered entity under section 95811(a) of the proposed regulation, the operators of cogeneration plants serving industrial energy needs should directly receive free allowances. CARB should ensure that the potential industrial customers' investment in combined heat and power (CHP), with its significant greenhouse gas reduction benefits, is not discouraged by the Cap and Trade regulation. As currently structured, the Cap and Trade program will undermine the Scoping Plan's CHP goal by placing significant, additional direct compliance costs on new and existing cogeneration facilities, regardless of the efficiency of a particular facility, especially if the facility is sized to meet on-site loads and does not make substantial quantities of electric power for wholesale sales. This is particularly true in Praxair's case, where as the owner of the self-generation facility in a sector not provided any relief via direct allowance allocations, its potential investment in CHP could be rendered uneconomic because of the direct compliance burden, particularly when compared to electricity procurement from the grid where there is a potential level of rebate from the IOU or POU. The AB 32 Scoping Plan sets "a target of an additional 4,000 MW of installed CHP capacity by 2020, enough to displace 30,000 GWh of demand from other power generation sources." However, the Cap and Trade program does not account for the reductions in GHG emissions attributable to CHP facilities. The rationale for inclusion of CHP facilities in the Cap and Trade program states that "It is necessary to include emissions from cogeneration units because these units are widely used by industries and represent a large share of California GHG emissions. The use is expected to grow and the efficiency is expected to improve." This anticipated growth and efficiency enhancement is not recognized through financial support in the proposed regulation—the financial support provided through free allowances that is offered by CARB to many other industrial sectors. (PRAXAIR)

Response: Allowances are not allocated to cogeneration facilities separate from EITEs, for reasons discussed above. However, it appears that PRAXAIR's main interest is in onsite cogeneration, in which the facility is "sized to meet on-site loads." PRAXAIR is in the Industrial Gas Manufacturing industry, involved in hydrogen production. We modified Table 8-1 in section 95870 to add this industrial classification as an EITE. PRAXAIR will receive allowances through the product benchmarking methodology. In general, the cap-and-trade program does not account for reductions, but rather requires allowances for emissions. The regulation does not provide direct financial support for CHP, but instead uses price signals to support the production that is most efficient from a greenhouse gas perspective. It encourages the most efficient use of CHP within EITEs, and allows independent CHP to compete with carbon costs properly internalized.

I-118. Comment: The draft Cap and Trade Program does little to incentivize efficient CHP facilities. The District recommends free allowances or a reduction in the compliance obligation for emissions from high-efficiency CHP systems. The AB 32 Scoping Plan calls for the state to increase CHP energy generation by 30,000 GWh, yet the draft Cap and Trade regulation provides no incentives for development or expansion of CHP. In fact, by treating CHP facilities as any other combustion source and therefore creating a compliance obligation for these facilities, ARB is likely to discourage industries, including wastewater treatment facilities, from installing or expanding efficient CHP systems.

For example, at the District, staff has been considering upsizing our CHP facility to a unit that produces approximately 30 percent more power with only 10 percent additional fuel (natural gas) a project that would be a net environmental benefit. With the compliance burden that AB 32 Cap and Trade would assign to such an expansion, the return on investment may not warrant such a project. Instead, we will likely draw more of our power from the grid, adding more demand and increasing the number of renewable energy projects that power utilities are complete to meet the State's renewable energy portfolio goals.

We therefore suggest that CARB reincorporate the incentive for efficient CHP units by either including efficient CHP in Table 8-1: Industry Assistance, page A-76 of the draft regulations, making such facilities eligible for industry assistance in the form of free allowances, or by reducing the compliance obligation for GHG emissions from high efficiency CHP systems by giving GHG credit for the steam captured for useful work, as was the plan in the previous version of Cap and Trade. (CCCSD)

Response: As discussed elsewhere, we believe that CHP facilities exporting heat and power will be able to pass through the cost of compliance in the prices of their products, and that, given the multiple benefits of efficient CHP, the regulation will complement other regulatory incentives for CHP. Furthermore, since emissions from biomethane from wastewater facilities to not create a compliance obligation, it appears that CCCSD is likely to benefit economically from the upsizing of the CHP under consideration.

Allocate EITE for Electricity

I-119. (multiple comments)

Comment: The proposed regulations would not adequately compensate an EITE facility for GHG compliance costs associated with imported power.

Recommendation: Dow urges ARB to give EITE entities (rather than utilities and their governing agencies) the responsibility for deciding which GHG investments to pursue at EITE facilities.

Rationale: The ISOR specifies direct rebates to residential customers. The ISOR suggests that industrial electricity customers' allowance value would be provided through energy efficiency (EE) benefits, rather than bill relief. The ISOR states, "The proposed regulation limits how the return of allowance value to customers might function. Staff believes that any rebates to residential customers should be made as separate payments and not simply deducted from customer bills…."

Appendix J to the ISOR further states, "As shown in Table J-7, electric distribution utilities are expected to reduce the carbon costs faced by industrial sources due to power purchased from the grid. Staff envisions this compensation would be in line with that given to other customer classes. However, the form of compensation to industrial ratepayers might best be structured as energy-efficiency programs rather than per-customer rebates."

It is unclear, however, whether additional energy efficiency programs will have material value to EITE industries in the future, especially for those facilities, like Dow Pittsburg that have already implemented most of the efficiency measures. Energy-intensive entities have been leaders in EE because of the impact of energy costs on profitability. Even if an energy-efficiency program could be leveraged, an EITE entity may not be able to realize full carbon cost recovery. Energy efficiency programs and incentives may encourage incremental investments but they do not guarantee that EITE entities will be adequately compensated for the carbon costs associated with imported power. ARB also leaves this issue to be resolved by the CPUC, which further increases uncertainty related to this issue. (DOWCHEM1, DOWCHEM2)

Comment: Allocation of Allowances to Utilities Alone Will Not Assure Recovery of Carbon Costs Associated with Utility Power Imported by an EITE Entity: The proposed regulations would not adequately compensate an EITE for GHG compliance costs associated with imported power. While the ISOR appropriately contemplates direct rebates to residential customers, industrial customers' allowance value would be provided through energy efficiency (EE) benefits, rather than bill relief. (EPUC)

Comment: It is unclear, however, whether additional EE programs will have material value to EITE industries in the future. Energy-intensive entities have been leaders in EE because of the impact of energy costs on profitability. Moreover, even if an energy-efficiency program could be leveraged, a trade-exposed entity may not be able to realize full carbon cost recovery. Energy efficiency programs and incentives may encourage incremental investments but they will not adequately compensate EITE entities for the carbon costs associated with imported power. Importantly, CARB also leaves this issue to be resolved by the CPUC, which further increases uncertainty related to this issue. In other words, EE incentives, particularly those that have not yet been litigated, are not sufficient to ensure the competitiveness of EITE facilities.

The proposed regulation leaves EITE entities exposed to carbon costs associated with power imported from non-utility sources: The ISOR Table J-7, makes clear that EITE entities will be covered for the emissions costs associated with electricity generated and consumed "on site." As discussed above, this characterization leaves power imports from the utilities fully exposed. (EPUC)

> **Response:** Section 95892(a) was modified to require that allowances allocated to utilities "must be used exclusively for the benefit of retail ratepayers… consistent with the goals of AB 32." The CPUC and governing boards of publicly owned utilities will also impose limitations on the use of these funds. We agree that it is unclear whether additional energy-efficiency programs would have material value to some EITEs. Furthermore, we believe it is important for utilities to pass through allowance value in a manner that helps to minimize leakage from EITEs and incentivizes greenhouse gas reductions. The CPUC (for IOUs) and the publicly owned utility governing bodies have the authority to ensure that electricity rates for EITEs reflect carbon costs. We will continue to work with these entities to ensure that rates and uses of allowance value are appropriate.
>
> We determined the level of leakage risk for different covered sectors through the analysis that is found in Appendix K of the Staff Report. Instead of guaranteeing full carbon cost recovery, it determined the level of leakage risk for different industrial sectors and classified them into three categories: high leakage risk, medium leakage risk, and low leakage risk. Covered entities can receive compensation in the form of direct allocation from ARB and in the form of compensation from utilities. ARB will work closely with the CPUC to ensure that the level of compensation will align with that necessary to minimize leakage. Energy-intensive entities that have been leaders within their industrial sectors will benefit because the benchmark for the industry rewards such entities relative to their less-efficient competitors.
>
> The calculation of product and energy benchmarks does not account for indirect emissions from electricity purchased or imported by EITEs. As stated in footnote 8 on page 3 of Appendix A of the 15-day changes to the regulation, an adjustment factor was not made for power purchased in establishing the product-based benchmarks. This is because purchased power may not create an indirect carbon cost in all California utility service territories for EITEs that purchase from utilities. It is ARB's goal to see a carbon price properly embedded in all utility rates. If and when this occurs, the compensation for these indirect carbon costs and for indirect costs associated with electricity imported from non-utility generators could be incorporated into the product benchmarks (or reductions in these costs created in some other fashion) if needed to help minimize leakage.

I-120. Comment: The proposed regulation leaves EITE entities exposed to carbon costs associated with power imported from non-utility sources: The ISOR Table J-7, makes clear that EITE entities will be covered for the emissions costs associated with electricity generated and consumed "on site." As discussed above, this characterization leaves power imports from the utilities fully exposed. Moreover, an additional ambiguity in the proposed regulation—the boundary between "imported" and "on-site" power—leaves one additional category of EITE entities exposed to carbon costs associated with power. It is not clear whether entities securing non-utility power using non-utility wires would qualify as importers or receive a free allowance allocation as "on-site" generation to cover the emissions associated with that power. The proposed regulation's use of the term "on-site" power is unclear. Does this mean that carbon costs for electricity must be generated on the same physical real property as the host operation? If so, the definition would preclude cost recovery by entities that own and operate generation, or purchase from non-utility generators that may not be located directly on the host property site.

Consider the following scenarios:

- EITE 1 owns a CHP generator that delivers power to its industrial operation, and that generator is located physically on the same real property as the industrial operation;
- EITE 2 holds an ownership interest in a CHP generator that is physically on the same real property as the industrial operation and buys its power from that generator;
- EITE 3 owns a CHP generator that delivers power to its industrial operation, but that generator is not located physically on the same real property as the industrial operation;
- EITE 4 holds an ownership interest in a CHP generator that is not physically on the same real property as the industrial operation and buys its power from that generator.

There appears to be no basis on which to discriminate against any of these EITE entities based on the geographic location of the serving generation or the ownership. Regardless of ownership or geography, these entities will incur carbon costs for their power use—whether directly as a generating cost or indirectly as a power purchase cost. Likewise, regardless of ownership or geography, these entities will not have an alternative means to recover their carbon costs. For this reason, the boundary of free allowance allocation can and should be drawn simply. There should be no distinction drawn based on the physical location or ownership of the generation. (EPUC)

> **Response:** Section 958102 precisely defines a facility as "any physical property, plant, building, structure, source, or stationary equipment located on one or more contiguous or adjacent properties in actual physical contact or separated solely by a public roadway or other public right-of-way and under common ownership or common control, that emits or may emit any greenhouse gas."

The regulation applies to operators of facilities, including electricity generating facilities (sections 95812(c)(1) and (2)(A)). Compliance obligation falls on operators of facilities that have operational control. "Operational control" and "operator" are defined in section 95802(a)(186) and (187). Operational control means the authority to introduce and implement operating, environmental, health and safety policies, and if such authority is shared, the operator is the entity holding the permit to operate from the local air pollution control or air quality management district.

The descriptions of the cases provided by this commenter are not sufficiently precise for us to determine the exact treatment of each situation. As discussed elsewhere, compensation to EITEs to reduce carbon costs in purchased power depends on future analysis of rates properly reflecting carbon costs, and on actions of the CPUC and the governing bodies of publicly owned utilities. We continue to work with the CPUC, utilities, and stakeholders to make the regulation as equitable as possible for all EITEs.

I-121. (multiple comments)
Comment: As CARB correctly notes, current competitiveness can be maintained only if the regulations ensure that all GHG compliance costs are recovered. CARB's proposal does not meet the agency's own objective of ensuring that trade-exposed entities receive coverage of the emissions associated with electricity use. CARB can mitigate the potential competitive impacts in one of two ways. Under the proposed framework, CARB can require the utility to share the benefits of free allowance value with trade-exposed entities through direct rebates. The direct rebate could be based on the average carbon adder factor per MWh. This can be accomplished with the incorporation of the following language as subpart D):

Section 95892(b)(3)

Auction proceeds obtained by an electrical distribution utility shall be used exclusively for the benefit of retail ratepayers of each electrical distribution utility, consistent with the goals of AB 32, and may not be used for the benefit of entities or persons other than such ratepayers.

(D) <u>Utilities shall provide auction proceeds to energy-intensive, trade-exposed industrial ratepayers through a direct rebate equal to the carbon costs embedded in the ratepayer's average MWh rate multiplied by the MWh consumed by the ratepayer.</u>

An alternative, simpler way to achieve this objective would be for CARB to provide an EITE entity a direct allocation of free allowances for power purchased from a distribution utility. To avoid double counting, CARB could then exclude these allowances from the allocation of free allowances to the entity's serving utility. If CARB elects to take this approach, the following modifications should be reflected in section 95891:

Section 95891(a):

"A_t" is the amount of California GHG allowances directly allocated to the operator of an industrial facility for all activities with a product output-based allocation from budget year "t." <u>This allocation shall include allowances to cover the carbon costs associated with electricity imported from an interconnected utility.</u>

Section 95891(c):

"A_t" is the amount of California GHG allowances directly allocated to the operator of an industrial facility with a thermal energy-based allocation from budget year "t." <u>This allocation shall include allowances to cover the carbon costs associated with electricity imported from an interconnected utility.</u>

In addition, the final regulation should provide for allowance allocations to recover the carbon costs of non-utility power, whether self-generated or otherwise procured over proprietary wires. The following modifications are required:

Section 95891(a):

"A_t" is the amount of California GHG allowances directly allocated to the operator of an industrial facility for all activities with a product output-based allocation from budget year "t." <u>This allocation shall include allowances to cover the carbon costs associated with electricity self- generated or procured over private distribution facilities from a source other than facility's interconnected utility.</u>

Section 95891(c):

"A_t" is the amount of California GHG allowances directly allocated to the operator of an industrial facility with a thermal energy-based allocation from budget year "t." <u>This allocation shall include allowances to cover the carbon costs associated with electricity self-generated or procured over private distribution facilities from a source other than facility's interconnected utility.</u>

In short, CARB should eliminate any distinctions between power produced "on-site" and imported. Making the distinction solely based on whether or not the power is procured from the entity's interconnected utility. To better ensure that all imported power receives the same treatment, CARB could provide for a direct allocation of allowances (in sections 95891(a) and (c)) to cover the carbon costs associated with imported power from a utility. (EPUC)

Comment: CARB's proposed regulations leave open critical gaps that may compromise its ability to adequately provide transition assistance to EITE entities. CARB proposes to provide free allowance allocations to EITE entities to "avoid imparting undue initial economic gain or loss" in the early program years and to prevent leakage. CARB notes that current competitiveness is maintained if the free allocation covers all of the EITE's carbon costs (Free allocation = carbon costs – carbon cost recovered). While CARB intends to directly reduce carbon costs associated with heat consumption and on-site energy consumption, an EITE facility will be exposed to GHG compliance costs associated with "imported" power. CARB does not intend to provide free allocation of allowances for the carbon costs associated with imported power because it assumes that carbon costs associated with these imports will be offset by the allocation of allowances to its interconnected utility: Indirect carbon costs arising from purchased electricity from the grid will be reduced through compensation from distribution utilities that are given allowance value for the purpose of ratepayer protection (see Appendix J, at J-32). The rationale for section 95891(c) reiterates these expectations. In discussing thermal-energy based equations, the ISOR states: Electricity purchased from off-site is not part of the thermal energy-based allocation equation but receives indirect compensation through (the) distribution utility to offset the expected indirect GHG costs, as described in section 95892 (see ISOR at IX-59).

The regulations, however, do not assure that this form of compensation will occur. In addition, CARB's analysis leaves unclear the boundary between power "produced on-site" and "imported from off-site." The place in which this boundary is drawn will undermine the goal of maintaining EITE entities' competitiveness. While the proposed regulations aim to maintain competitiveness by permitting carbon cost recovery, the implementation of this principle could be comprised, depending on the mechanics of the allowance allocation formula. First, if the utilities return the allowance value to industrial customers as contemplated in the ISOR, an EITE entity may receive no coverage for the carbon costs embedded in its utility rates. Second, depending on where the boundary is drawn between "on-site" and "imported" power, EITE entities receiving power from non-utility generation over non-utility wires may not receive any coverage for the carbon costs associated with the electricity they consume. As noted below, effective transitional assistance to industrial facilities requires recovery of GHG compliance costs associated with power purchased from a utility or non-utility. (EPUC)

> **Response:** We prefer allocation to be provided per unit of production wherever possible. The goal of this approach is to protect production activities, not emitting activities. Updated compensation provided per megawatt-hour (MWh) consumed does not create the correct incentives to conserve electricity and thus reduce greenhouse gases.
>
> As discussed elsewhere, we believe that, once utility rates reflect carbon cost, it might be appropriate to modify the benchmarking methodologies to include electricity purchased by EITEs, including electricity purchased from utilities or from other electricity generators. ARB will work closely with the CPUC and the publicly owned utilities toward ensuring that rates reflect an appropriate carbon cost, and that allowance value flows appropriately to minimize leakage and transition risk for EITEs.

I-122. Comment: CHP users should be provided with allowances for any emission savings resulting from installing energy efficient CHP plants. Allowances should be calculated by comparing the CHP efficiencies with the weighted average energy efficiency of all natural gas electric generation plants located in California. (SWGASCORP)

> **Response:** Allowance value is allocated to EITE facilities for leakage prevention and transition assistance. The goal of the allocation methodology is not to explicitly incentivize or “pick winners” between various greenhouse gas reduction strategies, including CHP. Correct carbon pricing will create the proper incentives for instillation of efficient CHP.

Long-Term Contracts

I-123. (multiple comments)
Comment: ARB's essential premise in developing the Cap and Trade Rule provisions for electrical generators is that they can pass through the costs of GHG allowances purchased at auction under the Cap and Trade Rule. This premise is not correct, for electrical generators like HDPP, as the staff suspected. The ARB staff should now quantify the effects of "locked-in" contracts over time; develop alternatives for addressing this issue; consult with the CPUC, CEC, California ISO, the affected electrical generators and other affected stakeholders; and develop a solution that complies fully with the provisions of AB 32, the cost-containment and other principles adopted by the Board in approving the Cap and Trade Rule and the other provisions of the final Cap and Trade Rule to be developed during 2011 by the Executive Officer. (HDPP2)

Comment: Some California generators sell power under electricity contracts that do not allow the pass through of the costs of acquiring GHG allowances during the early years of the California Cap and Trade program. These contracts were lawfully entered before the proposed Cap and Trade compliance periods and they continue into the first compliant period (and perhaps beyond)—but they expire at fixed terms. ARB's proposed Cap and Trade program excludes electricity generators from the allocation of free allowances, based on the assumption that all electricity generators are capable of passing these costs through the wholesale power market. This assumption appears to be generally correct. However, this assumption is not correct for some generators for some years, for the reason stated above, with potentially severe, unintended consequences to the affected generators and California energy markets. (HDPP1)

Comment: Both the staff report and Appendix J (Allowance Allocation) note that there are independent power producers who, due to terms in pre-existing contracts, are unable to pass-through the cost of allowances in their electricity prices, and that modification of the regulation may be needed to include provisions to address these situations. WPTF urges inclusion of provisions in the regulations that:

- Define the conditions under which an independent power producer would be eligible to receive allowances (e.g., contracts entered into after adoption of AB 32 would not be eligible for such relief).

- Require documentation by the producer to demonstrate that it meets these conditions.
- Provide for direct allocation of allowances to independent power producers to cover emissions associated with these contracts.
- Reduce the direct allocation of allowances to individual electrical utilities that are counter-parties to these contracts by the amount of allowances directly allocated to independent power producers. (WPTF)

Comment: CARB should evaluate pre-AB 32 contracts on a case-by-case basis. Whether a contract includes such a cost recovery mechanism should be evaluated by asking the following questions:

1. Was the contract entered into or its pricing provisions amended after the effectiveness of AB 32 (December 31, 2006)? If the answer is yes, then the parties should be presumed to have considered GHG cost risk.

2. Does the contract contain a "change of law" provision that provides for a re-open opportunity in the event that by virtue of new law or regulation in which case the parties will meet and confer/renegotiate to maintain the balance of risks and benefits? If the answer is yes, then the contract has a mechanism to directly consider new costs and risks such as those that are the result of GHG regulation.

3. Does the contract provide an explicit accounting for and pass-through of GHG costs? Prior to AB 32, contracts like that were rare, but if the answer is yes, then the parties have directly considered GHG cost risks.

4. Does the facility owner make the decision whether to generate and deliver energy to the purchaser? If the answer is yes, then the project has the ability (a mechanism) to take GHG costs into consideration when deciding whether to generate energy.

5. Does the contract provide for energy payments that are measured by a competitive market that allows bidders to include GHG costs? If the answer is yes, the purchase agreement has a payment mechanism that includes appropriate GHG costs. As CARB staff correctly points out "because the price of electricity in the (CAISO) wholesale electricity market will reflect the cost of those purchased allowances, staff expects that independent generators will incorporate their cap and trade compliance costs into their bids in the wholesale power markets" (ISOR at II-32). For other pre-AB 32 contracts, GHG costs "may be addressed through the recently announced combined heat and power settlement at the California Public Utilities Commission" (ISOR footnote 22 at II-32).

If the answer to all of these questions is "no", there is no need for further investigation; the particular generator's contract clearly does NOT provide a mechanism for appropriate recovery of GHG costs. For Fresno Cogeneration Partners, LP (one of the generators with which Wellhead has a relationship), the answer to each of the questions is "no." This project operates under an agreement where the purchasing utility makes the dispatch decision and pays for delivered energy based on: i) start-up costs; ii) a fixed heat rate, iii) the cost of natural gas fuel, and iv) a fixed variable operating and maintenance expense. The price paid is independent of and does not include any consideration of GHG or any other new or emerging cost components. This project, accordingly, precisely fits the case CARB staff recognized. (WEC)

Comment: If an Independent Power Producer (IPP) is operating under an existing contract that predates the effective date of Assembly Bill (AB) 32 and that provides no reasonable means to recover greenhouse gas (GHG) allowance costs, these IPPs should be provided access to allowances for the remaining term of their existing contract. This approach would place them on a basis comparable to other electric generators that have a reasonable means of GHG cost recovery, particularly the electric utilities. To accomplish this outcome, we recommend the following language changes in two separate sections of the proposed regulation.

Add subsection (d) to section 95890. General Provisions for Direct Allocations.

<u>(d) Eligibility for Electric Generators not otherwise defined as an Electrical Distribution Utilities. An electric generator shall be eligible for free, direct allocation of California GHG allowances if it has complied with the requirements of the MRR and has obtained a positive or qualified verification statement on its sales number for the prior year pursuant to the MRR; it is operating under an existing contract that was effective as of the effective date of AB 32; and it has demonstrated to the satisfaction of the Executive Officer that it cannot reasonably expect to recover the costs of GHG allowances needed to meet its compliance obligation under the existing contract.</u>

Modify section 95802 as follows:

> (a)<u>(153). "Pre-AB 32 Power Purchase Agreements" means a power purchase agreement for the sale of electricity to an electric distribution utility, which (1) was originally executed on or before December 31, 2006; and (2) does not provide the seller with a reasonable opportunity to recover its costs of complying with regulations governing emissions of greenhouse gases. A power purchase agreement shall no longer qualify as a Pre-AB 32 Power Purchase Agreement if, after the effective date of this article, it expires, terminates, or is amended to change any of the terms governing the price or amount of electricity sold pursuant to the agreement or the expiration date of the agreement.</u>
>
> <u>The Executive Officer shall establish guidelines for determining whether a power purchase agreement provides the seller with a reasonable opportunity to recover its costs of complying with regulations governing emissions of greenhouse gases. In developing these guidelines, the Executive Officer shall consider:</u>
>
> a. <u>Whether the power purchase agreement includes provisions on changes in laws or regulations or force majeure provisions that affect recovery of</u>

the cost of complying with regulations governing emissions of greenhouse gases.

b. Whether loss of some or all of the deliveries from the units providing power pursuant to the power purchase agreement would affect the reliability of the electric grid.

c. Whether the power purchase agreement provides for compensation in part from market prices, and whether those market prices include the costs of generators' compliance with regulations governing emissions of greenhouse gases.

d. The extent to which the owners or operators of the units providing power pursuant to the power purchase agreement control the dispatch of the units.

e. The net effect on greenhouse gas emissions if the units providing power pursuant to power purchase agreement do not recover the costs of complying with regulations governing emissions of greenhouse gases and, as a result, shut down.

Add the following language to section 95892(c), Allocation to Electrical Distribution Utilities for Protection of Electricity Ratepayers:

(3) The electrical distribution utility shall set aside allowances for each calendar year in an amount sufficient to satisfy the compliance obligation of any covered entity attributable to generation of electricity purchased by the electrical distribution utility pursuant to a Pre-AB 32 Power Purchase Agreement, as defined in Subarticle 2. These allowances shall be set aside prior to each auction that the electrical distribution utility offers allowances for sale. If the verified emissions attributable to the Pre-AB 32 Power Purchase Agreements exceed the amount of allowances set aside by the electrical distribution utility, the electrical distribution utility shall obtain the remaining amount of allowances from the next quarterly auction, or through the Allowance Price Containment Reserve. The electrical distribution utility shall transfer the required amount of allowances to the covered entity from which it purchases electricity under the Pre- AB 32 Power Purchase Agreement no later than 30 days before the covered entity's annual and triennial compliance obligation. (IEPA)

Comment: Add to section 95802 (a) as follows:

"Pre-AB 32 Power Purchase Agreements" means a power purchase agreement for the sale of electricity to an electric distribution utility, which was originally executed on or before December 31, 2006 and does not provide a mechanism for recovery of greenhouse gas compliance costs. A Pre-AB 32 Power Purchase Agreement shall not include a power purchase agreement that, after the effective date of this article, has expired, is terminated, or is amended to change any of the terms governing the price or amount of electricity sold pursuant to the agreement or the expiration date of the agreement. Whether a power purchase agreement qualifies as a Pre-AB 32 Power Purchase Agreement shall be subject to review by the Executive Officer to ensure compliance with the preceding requirements. (WEC)

Comment: Appendix J of the ARB staff report recognizes the potential issue surrounding stranded costs created by the currently proposed GHG cap and trade program and born by some independent energy producers under existing power agreements. Some pre-existing power purchase contracts do not allow the generator to pass-through the cost of purchasing allowances or offsets. NextEra Energy believes that the proposed regulation needs to be amended in order to mitigate the impact that could result from these situations. The addition of a provision to mitigate these stranded costs would require ARB to at least: Define the eligibility requirements for this provision; Establish the conditions under which these facilities continue to receive assistance or relief; Determine the form the relief will take (example-allowance allocation, auction revenue, surcharge to off-taker, etc.); Documentation requirements. (NEXTERAENERGY)

Comment: Section 95811 requires generators and importers of electricity into California to account for the CO_2 emissions associated with their power production and imports. Shell Energy understands the need to include emissions from the power sector under the cap and trade program. However, for generators located within, or connected to the California Grid that entered forward term contracts at fixed prices, this requirement may create an economic loss that was not accounted for at the time the transaction was executed.

We recommend that a portion of the allowances for each affected vintage year be made freely available to generators who entered into forward term fixed price agreements prior to the ARB Rules having been adopted in order to prevent penalizing those entities that transacted in good faith under existing regulations. (SHELLENERGY)

> **Response:** We are aware of a potential inequity if generators, be they combined heat and power (CHP) facilities or other electricity generators, cannot pass through carbon costs to purchasers. This response first explains our approach to long-term contract issues for electricity generation facilities that are not CHP (cogeneration) facilities and then addresses specific comments.
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> Stakeholders who are parties to contracts for which there are no cost pass-through provisions approached ARB prior to the release of the proposed cap-and-trade regulation. ARB staff collaborated with industry to develop a survey to assess the magnitude of the issue. Staff received over 50 responses to a survey

sent out to California generators. In addition, we met with many representatives of electricity generating facilities, most of whom were also survey respondents.

Most of the long-term contract issues concern CHP facilities; we have responded to CHP long-term contract issues contracts in a separate section. Here we consider only facilities concerned with long-term contract issues that are not CHP facilities. We note that the facility operated by Fresno Cogeneration Partners LP provides electricity to the grid and is not considered to be a cogeneration because it does not provide useful thermal energy. Because we have a great deal of information provided about individual facilities' contract issues, we take a case-by-case approach, and build on that approach by categorizing facilities with similar issues.

One category is facilities that have contracts that end before January 1, 2013. We have resolved the issue for these facilities by modifying section 95856 and the definition of "compliance period" in section 95802(a) such that there is no compliance obligation for emissions prior to 2013.

Another category consists of facilities with contracts that either commenced or were amended after the passage of AB 32. For these facilities, we believe there was an opportunity for both parties to assess risk and incorporate expectations about future carbon costs while negotiating contracts or amendments, and we believe no further action is required.

A third category of facilities with long-term contracts have no compliance obligation, or an insignificant compliance obligation, because most or all of their emissions are excluded pursuant to section 95852.2. For example, section 95852.2 clearly excludes fugitive and process emissions from geothermal facilities from a compliance obligation. Most geothermal facilities have no other emissions with a compliance obligation, although a few may have a compliance obligation for a very small amount of emissions from fossil fuels.

A fourth category consists of electricity-generating facilities that have long-term contracts with investor-owned utilities. For these contracts, we believe the proper venue for assessing and resolving contract issues is the California Public Utilities Commission (CPUC) proceeding addressing utility costs and revenue issues associated with greenhouse gas emissions.

A fifth category includes facilities that combust primarily coke and coal. Some of these facilities are owned by GWF, and we address long-term contract issues for these facilities below in our response to GWF's comments.

In addition, we are aware of a very small number of facilities that do not fall into any of the categories described. We continue to work with stakeholders to find solutions for these.

We have strongly encouraged stakeholders on both sides of these contracts to renegotiate the contracts so that neither sellers nor purchasers are disadvantaged, and costs are passed through when appropriate. We note that in the electricity sector, there are many sophisticated methods of dealing with risk in electricity contracts. Parties may explicitly or tacitly assume risk, and prices may depend on the two parties' assumptions about future risk and who will bear it. Even with the information provided in response to the survey, it is not clear how issues of risk were resolved. This is one of the reasons that we encourage bilateral renegotiation. We are encouraged by progress reported by entities that have begun the renegotiation process.

With regard specifically to the HDDP2's comment. we note that we consulted with the CPUC, the California Energy Commission (CEC), and the California Independent System Operator (CAISO) as we developed our approach. We believe that long-term contract issues can be resolved by the parties themselves, or in other regulatory venues, and that HDPP2 does not face issues for its contract that ended in 2012.

Several commenters claim that the Staff Report or Appendix J stated that some power producers cannot pass through costs. This is not accurate. Both documents note that stakeholders have reported the inability to pass through costs in some cases, and the Staff Report notes that ARB will evaluate these cost pass-through issues on a case-by-case basis.

WEC requests that ARB evaluate contracts on a case-by-case basis, and we have done so for all facilities that participated in our survey and contacted us with information about their contracts. WEC also recommends five questions that could be asked for each contract, and states that if the answer to each question is no, then that contract does not have a pass-through mechanism. We asked some of these questions in the survey, and also asked stakeholders to provide additional information that would indicate need or potential for passing through carbon costs.

WEC states that Fresno Cogeneration cannot pass through costs due to the nature of the contract, including the assertion that price paid by the purchaser does not include any consideration of GHG emissions costs. Because the contract is with a utility, we believe the venue for resolving contract issues is the CPUC proceeding mentioned above. We did not add the definition proposed by WEC and instead have followed the approach discussed in this response.

NextEra Energy believes the regulation needs should be amended to provide for relief to parties involved in long-term contracts. We did not act on this recommendation because we believe that there are many other options to resolve these issues, and that the difficulty of assessing parties' assumptions about risk when contracts were negotiated makes a regulatory approach infeasible.

We did not modify sections 95890, 95802, and 95892(c) as requested by the Independent Energy Producers Association (IEPA) for the reasons above, and because we prefer the approach outlined in the beginning of this response.

Finally, notwithstanding our belief that issues can be resolved without changing the regulation, it is not our intent to provide allowances to entities for carbon costs that they do not, in some manner, incur. If pass-through of carbon costs in long-term contracts remains an issue in the future, we may consider other methods, including those mentioned by commenters, if necessary.

I-124. (multiple comments)
Comment: GHG allowances allocated to a purchasing utility should be redirected to suppliers under PPA's that do not provide for appropriate recovery of GHG costs. This approach does not require any change to the existing power contract and ensures that the purchasing utility, that has dispatch control, accounts for GHG allowance costs (along with all its other considerations) in their dispatch decision. Failure to provide for the purchasing utility's use of the allowances would almost certainly result in the purchasing utility dispatching a facility when lower GHG emitting facilities were available (because the GHG impact would be invisible to the purchasing utility). This outcome would directly contravene and thwart the basic purpose of AB 32. (WEC)

Comment: CARB's regulations could cause generators to not receive appropriate GHG cost recovery. Wellhead is concerned that if CARB is not careful about the precise wording of its regulations, it will create an entirely new class of generators that do not have appropriate GHG cost recovery. A number of existing power contracts that do have GHG cost recovery mechanisms contemplate that the seller will purchase any required allowances and that such costs will be reimbursed by the purchaser. However, language included in both Southern California Edison and San Diego Gas & Electric proforma Power Purchase Agreements (which are publicly available on the utility web sites as part of RFO activities) contemplate that such costs will be paid to the regulatory authority imposing the compliance requirement. Specifically, the PPAs state that:

"(Utility) shall reimburse Seller for (GHG costs) after (Utility's) receipt from Seller of documentation: (iv) that the (GHG cost) was imposed upon Seller by an authorized Governmental Authority in which the Generating Unit is located, or which otherwise has jurisdiction over Seller of the Generating Unit; and (v) that Seller has paid the agency identified under (iv) the full amount of the (GHG cost) for which Seller seeks reimbursement from (Utility).

Since the regulations are creating the framework where a third party(ies) may auction the allowances, the regulations have the potential to create a new class of generators that do not receive appropriate GHG cost recovery due solely to the allowance sales framework CARB is creating. To avoid this unintended outcome, CARB must either: i) be the entity that receives the payments for all GHG allowances purchased from an authorized auctioneer in complying with the regulations; or ii) make it very clear in the regulations that allowance costs procured from an authorized auction process shall be deemed to be procured from CARB for all purposes in a contract with provisions comparable to the proforma power purchase agreement language cited above. (WEC)

Comment: In the ISOR in support of the proposed regulation, CARB staff points out that there may be a class of generators that do not have a mechanism, contractual or otherwise, to recover GHG costs. "Some generators have reported that some existing contracts do not include provisions that would allow for full pass-through of cap and trade costs" (ISOR, p. II-32 at n22). In addition to the financial hardship, the inability to pass through these costs will distort the economic dispatch order, undermining the purposes of the Cap and Trade program, which is to implement the required AB 32 reduction of GHG emissions. These "counter to AB 32" impacts will occur because pre-AB 32 contracts without GHG cost recovery will cause less efficient generators (i.e., higher heat rate thermal units that emit more GHG per kWh produced) to appear less costly in the economic dispatch order of the purchasing utility because there are no GHG costs included. (WEC)

> **Response:** WEC suggests that GHG allowances allocated to a utility should be redirected to electricity generators that cannot pass through carbon costs. We disagree, and prefer our approach which calls for renegotiation of contracts to allow pass-through of costs when appropriate. WEC also has concerns about utility pro-forma power purchase agreements (PPAs) and wants ARB to make changes due to the PPA language. While we agree that the PPA language may not be appropriate, the proper venue for dealing with these issues is either through negotiation of contracts or through the CPUC proceeding mentioned above.
>
> We agree that under some contracts, utilities' economic interest could lead them to prefer to purchase electricity from higher-emission power plants if the carbon cost is not passed through. Again, this is a matter for the CPUC proceeding. We continue to work with CPUC on these issues so costs can be appropriately passed through, and in order to avoid distortions in the dispatch order that could cause higher-emission resources that cannot pass through carbon costs to generate electricity when electricity from lower-emission resources are available.

I-125. (multiple comments)
Comment: GWF requests that the proposed Cap and Trade Regulations be amended such that GWF receives allowances for its GHG emissions associated with its pre-AB 32 PPAs, declining throughout the 2012-2020 period at the same rate provided for the cement manufacturing industry. GWF's contractual obligations for its petroleum coke power plants were established pursuant to long-standing federal and state waste-to-energy policies that precede AB 32. This allowance allocation will serve to prevent the negative economic impact to GWF from its inability to recover compliance costs. (GWFPS1, GWFPS2)

Comment: GWF's electrical generating facilities are not the only petroleum coke fueled facilities in California. For example, some cement manufacturers burn petroleum coke for their energy needs. See ARB, Appendix F, Compliance Pathways Analysis, at p. F-26-27 (Oct. 28, 2010) (2006 data indicates that cement kilns employ petroleum coke for 19.7 percent and coal for 66.6 percent of their energy needs, respectively). The cement manufacturers with similar GHG emissions profiles and challenges related to GHG emission reduction would receive allowances under the proposed Cap and Trade Regulations. See sections 95890(a)-95891, and Tables 8-1, 9-1, and 9-2 (cement industry to receive direct allocations of allowances under a cap that declines to reach a 7.5 percent reduction by 2020). As a matter of policy equity, GWF should be treated similarly to similarly-situated industries. (GWFPS1)

Comment: ARB staff has acknowledged, however, that some long-term contracts may not permit IPPs to recover their compliance costs by increasing the price of electricity they sell to IOUs. ARB staff has further acknowledged that IPPs with long-term contracts that do not allow cost recovery may require special consideration in the proposed Cap and Trade Regulations. ARB, Appendix J, Allowance Allocation, p. J-16 n. 15 (Oct. 28, 2010). GWF could not recover its compliance costs because the avoided cost rate (as defined above) would not reflect the high cost of compliance that GWF would incur relative to the electricity market as a whole. Over the course of the three compliance periods, GWF's compliance costs would quickly reach enterprise threatening levels. (GWFPS1)

Comment: GWF's 30-year Standard Offer power purchase agreements (PPA) pre-date AB 32 and place GWF in the category of independent power producers (IPP) without a reasonable basis for recovery of compliance costs associated with the proposed Cap and Trade Regulations. As described in detail below, the proposed Cap and Trade Regulations will have an immediate and potentially crippling impact on GWF's enterprise because the Cap and Trade compliance costs for its petroleum coke power plants due to the chemical makeup (high carbon content) of the waste fuel source are significantly higher than a typical natural gas fueled power plant and these costs were not anticipated when the PPAs were executed in the mid 1980s. Therefore, the PPAs do not provide a mechanism under which GWF could recover compliance costs related to the use of a byproduct fuel source associated with the proposed Cap and Trade Regulations. (GWFPS1, GWFPS2)

> **Response:** Our overall approach to allocating allowances to industry is product-based and energy-based benchmarking. This is to encourage the most GHG-efficient methods of production. We have not used the benchmarking methodology for the electricity industry, because electricity production in California is not an energy-intensive trade-exposed (EITE) industry. However, we note that if such a methodology had been used, carbon-intensive electricity such as that produced at GWF’s coal and coke burning power plants would have received far fewer allowances than less carbon-intensive power plants. Since electricity generation is not an EITE industry, we treat it differently than cement manufacturing, which is energy-intensive and trade-exposed. Electricity

generators are expected to pass through the carbon cost to purchasers of electricity. Because GWF sells power to an IOU, we encourage GWF first to work with its counterparty to renegotiate contracts, and to participate in the California Public Utilities Commission proceeding addressing utility costs and revenue issues associated with greenhouse gas emissions.

Generation facilities such as GWF's plants that use alternative, high-emitting, sources of fuel were placed into service under a policy that would encourage the development and use of alternative fuel sources, and required contract structures to ensure consistent delivery of electricity. The qualifying facility (QF) settlement between CHP and cogeneration operators and the utilities addresses the cost-recovery of a portion of the GHG costs for these plants, but it does not cover all of the compliance costs or sources of fuel that emit GHGs that exceed that of an efficient natural gas power plant. However, one of the purposes of this cap-and-trade regulation is to encourage the refueling of these types of plants and to move toward the use of fuels that will help California to meet AB 32 goals of reducing GHG emissions. Because the regulation's purpose is to encourage switching to less carbon-intensive production, we also encourage GWF to consider repowering their power plants to use less carbon-intensive fuels. We understand from informal discussion with GWF that this may be possible.

We will continue to work with GWF to investigate potential modification of power plants to reduce emissions, and on other options to address GWF's concerns.

I-126. (multiple comments)
Comment: Fairness of allocations and pass-through costs for IPPs should be thoroughly developed in a public participatory process. The proposed rule provides for free allocations to the electric utilities, but there is no corresponding free allocation to the merchant or contracted power plants. These facilities will be placed at an extreme economic disadvantage because the independent power producers (IPP) and qualified facilities (QF) cannot pass through environmental control costs to the consumers. This is a part of the contract with the utility and is also part of the law that formed the basis of the IPPs and QFs. Constellation Energy believes that the allocation scheme for all generating facilities should be rethought to help smooth the imposition of a carbon price to ensure the success of the program. (CONSTELLATIONENERGY)

Comment: Constellation Energy requests that a formal public participation process be initiated to assess the issue of pre-existing power purchase agreements with IPPs. The issue of pass through of carbon costs must be resolved. (CONSTELLATIONENERGY)

Response: Constellation Energy is able to pass through certain carbon costs for electricity sold to utilities under the terms of the QF settlement. However, because the QF settlement encourages low-emission electricity production, and Constellation's power plants are high-emission facilities, not all of the costs can be passed through. This is consistent with the goals of this regulation.

Furthermore, the CPUC proceeding mentioned above is a public participation process that will include assessing pre-existing power purchase agreements between utilities and IPPs, and that is the best venue for this issue.

I-127. (multiple comments)
Comment: In developing its approach for the Cap and Trade program, ARB has attempted to create incentives to reduce emissions, to treat all covered entities fairly and equitably, to protect electric utility customers, to protect industry and to prevent leakage. This proposed limited free allowance provision for "locked-in" electricity generators would serve ARB's goals of fairness and equity in the Cap and Trade program. If they do not receive this limited relief, electricity generators with "locked-in" power sales would face massive costs that they could not pass through, unlike other generators. As described above, the "locked-in" generators would face new regulatory compliance costs that are new and highly disproportionate to any prior regulatory costs. Neither the Legislature nor the Governor anticipated that AB 32 would impose such costs and not allow them to be passed through. Neither did the ARB Board when it adopted the AB 32 Scoping Plan or ARB staff when they proposed the PDR for a Cap and Trade Program in 2009.

Also, the Legislature, Governor and ARB clearly desire to create incentives to invest in technology that lowers GHG emissions. The Cap and Trade program should not punish low GHG-emitting plants. If all wholesale generators are required to purchase allowances through the auction, the end result would be that some high-efficiency, low emissions plants are punished while less efficient, but higher GHG emitting plants are not. Instead, the program should provide incentives for the reduction of GHG emissions through the use of benchmarks that recognize more efficient power plants, such as the most efficient, new combined cycle natural gas plants.

The California power market would continue to receive the power from the "locked-in" generators. In consultation with CEC and CPUC, ARB could determine the appropriate deductions from the aggregate annual free allowance pool during the early years of the program. ARB, also in consultation with CEC and CPUC, could also adjust its future allocations of free allowances during each compliance year to achieve equity among the utilities and generators during each compliance year. Of course, the relief provided should only extend to the amounts of power "locked-in" for the "locked-in period and should expire when the contracts expire, terminate or are materially amended. (HDPP1)

Comment: Some California generators sell power under electricity contracts that do not allow the pass through of the costs of acquiring GHG allowances during the early years of the California Cap-And-Trade program. Without a mechanism to pass-through GHG allowance costs, these "locked-in" generators would have to purchase allowances to cover their compliance obligations but, unlike other generators, they could not pass the costs through the California energy markets to the utilities. These costs will vary depending on the price of allowances and the levels at which the affected power plants are dispatched by the contract customers, but could easily total from $16 million to $80 million per year for a nominal 75 MW combined-cycle power plant. These costs would place an enormous financial burden on the generator which could adversely affect the generator's ability to fund plant maintenance activities, to purchase fuel, to compete with other generators, to generate electric power for California consumers, and even to remain in business.

The proposed solution is ARB should cap the affected generators but allocate "free" allowances in a limited amount for a limited time to electricity generators located in California whose existing contracts do not allow the pass-through of Cap and Trade allowance costs. After the "lock-in" period, the covered generator would participate in the GHG auction like all other generators. The amount of free allowances allocated should be determined by applying current GHG emission benchmarks for electricity generation located in California. During the first compliance period (2012-2014), the benchmark for electricity generating power plants should be the GHG emission performance standard adopted by the CEC in 2007, which is 1,100 pounds (0.5 metric tons) of CO_2e per megawatt hour (MWh) of electricity. See 20 CCR section 2902.

The free allowances would only be made for the first Cap and Trade compliance period (2012-14), unless extended by further ARB Board action based on how the program works during the first compliance period. No banking or monetization of these allowances would be allowed. Eligible generators would be defined in ARB's final Cap and Trade regulation to include a facility with one or more power sales contracts executed before [November 24, 2009] that govern the facility's electricity sales and provide for sales at a price (whether a fixed price or a price formula) for electricity that does not allow for recovery of the costs of compliance with the limitation on greenhouse gas emissions under ARB's Cap and Trade regulation.

The owner or operator of the power plant would cease to be eligible to receive "free" GHG allowances when the contract expires, is terminated or is materially amended in a way that changes the price (whether a fixed price or price formula) for electricity, the quantity of electricity sold under the contract, or the expiration or termination date of the contract. To be eligible to receive "free" GHG allowances, the owner or operator of a "locked-in" generator would have to submit the following information to the Executive Officer within 60 days after the effective date of the final ARB Cap-And Trade rules, and also not later than [September 30] of each vintage year for which the generator wishes to receive GHG emission allowances:

(A) Identify each owner and each operator of the facility.
(B) Identify the units at the facility and the location of the facility.
(C) Certification by the designated representative that the facility meets all the requirements of the definition of a "locked-in" generator.
(D) The expiration date of each "locked-in" electricity sales contract.
(E) A copy of each "locked-in" electricity sales contract, to be submitted to ARB as confidential business information.

Not later than 30 days after a facility or a contract ceases to meet the eligibility requirements for distribution of" free" GHG emission allowances, the designated representative of such facility must notify the Executive Officer in writing when, and on what basis, such facility or contract ceased to meet such requirements. (HDPP1)

Comment: The High Desert Power Project (HDPP) believes that we can compete and provide cost-effective and low-emitting electric power to the California market under the ARB's Cap and Trade Rule with one critical exception: unlike some other electrical generators, we cannot pass the cost of GHG allowances to the markets during 2012 due to a locked-in power sales contract. The ARB's proposed Cap and Trade program will affect the various segments of the electricity sector differently. POUs and IOUs would receive direct (i.e., free) allocation of GHG allowances. However, for independent electricity generators, such as HDPP, ARB staff assumed this part of the electricity sector could pass-through 100 percent of the cost of the allocations to the wholesale power market (see ISOR, Appendix J, J-10) and therefore proposed that wholesale electricity generators be required to purchase all GHG allowances from auction from the outset of the program in 2012. Wholesale electricity generators would not receive any direct (i.e., free) allocation of allowances, starting in 2012 (see ISOR, Appendix J, J-16).

Unfortunately, the HDPP Plant currently has a fixed price contract to sell electricity from the period of February 2011 through December 2012. At the time the contract was entered in 2006, it was not anticipated—and could not reasonably have been anticipated—that HDPP would need to purchase over 1.5 million GHG allowances in 2012. Because HDPP has no mechanism to pass through the carbon costs of the proposed Cap and Trade program, HDPP would bear the entire cost of purchasing GHG allowances at a public auction to cover their compliance obligations, unlike other electric generators. (The HDPP Plant may also be able to obtain GHG offsets, but the proposed rule limits offsets so severely that the HDPP Plant could not operate at commercial levels with GHG offsets). If HDPP were to purchase all GHG required allowances for calendar year 2012 through auction at the price levels contained in the proposed Cap and Trade Rule, the 2012 cost could range from approximately $16- $80 million (at the floor or reserve prices in the proposed Cap and Trade sections 95911, 95913). Costs could be even higher if HDPP Plant dispatch increases in 2012. For many generators that are unable to pass through these costs, the added costs of purchasing GHG allowances could be punitive, could severely impact the generator economically and could even result in some cases in a suspension in operations to deal with this financial crisis which would adversely affect electric reliability in the State. We do not believe that the Legislature intended this result when it enacted AB 32, that the Governor intended this result when he signed AB 32 that the ARB Board intended this result when they adopted the AB 32 Scoping Plan or that ARB staff intended this result when they developed or proposed the California Cap and Trade program. To cure this fundamental inequity, we have prepared two alternative solutions and presented them to ARB staff:

I. The ARB Board should adopt language to provide direct allocations for the first compliance period (which runs through 2014) where an affected independent energy generator can show, to the satisfaction of the Executive Officer, that it cannot pass-through the cost of purchasing allocations due to the existence of a fixed price contract; or
2. The Board should provide clear direction to the Executive Officer to work with "locked-in" generators, CEC, and other stakeholders during the first half of 2011 to provide appropriate, limited relief in the final Cap and Trade Rule before the Executive Officer sends it to OAL.

Add the following language to the Board Resolution to be adopted on December 16, 2010:

"WHEREAS, some California electrical generators have reported that some existing power sales contracts do not include provisions that would allow full pass-through of cap and trade costs. These contracts pre-date the ARB's development of a proposed California cap on GHG and a proposed market-based compliance mechanism regulation. Many of these contracts may be addressed through the recently announced combined heat and power settlement at the California Public Utilities Commission but some may not be addressed. Staff continues to gather information, consult with CPUC, CEC, the California ISO and affected stakeholders and to evaluate this issue to determine whether some electrical generators may require special treatment for a limited period on a case-by-case basis;"

"BE IT FURTHER RESOLVED, that the Board authorizes and directs the Executive Officer to meet and confer during the first quarter of 2011 with California electrical generators that provide power to the California market subject to existing power sales contracts that do not include provisions that would allow full pass-through of cap and trade costs and, as appropriate, to provide special treatment in the final regulation to those affected generators, such as making direct allocations to those affected generators for the first compliance period (which runs through 2014) if an affected generator can show, to the satisfaction of the Executive Officer, that it cannot pass-through the cost of purchasing GHG allowances due to the existence of a fixed price or fixed formula contract." (HDPP2, HDPP3)

Comment: ARB should estimate the aggregated allowances allocated to "locked-in" generators during each year of the Cap and Trade program. The amount will diminish as the "lock-in" contracts expire. During the initial years when the aggregate amount is highest, the effect on the overall Cap and Trade and AB 32 programs should be minimal since the program is designed to phase in gradually during those years. When the pace of GHG reductions increases in later years under the Cap and Trade program, the aggregate allowances allocated to "locked-in" generators also diminishes due to contract expirations.

The U.S. Senate, when considering a similar Cap and Trade program, included specific allowance relief for "locked-in" generators. The Senate provision includes both IPPs and cogenerators. In light of the cogeneration settlement in California allowing cogenerators to pass through GHG allowance costs directly to their utility counter-parties, it appears that ARB need not address the issue for some or all California cogenerators. However, ARB should provide allowance relief for other "locked-in" California generators that are not covered by the settlement, on appropriate and fair terms.

Under ARB's October 28, 2010 proposal, HDPP would receive no GHG allowances, would have to purchase over 1.6 million GHG allowances at auction in 2012 but would have no way to recover or "pass through" its GHG allowance costs. Depending on the auction prices in 2012, the costs could far exceed $16 million (at $10 each) and even approach $80 million (at $50 each). Costs could be even higher if plant dispatch increases in 2012. These costs would cripple this plant. It could result in a quick failure of the plant economically and even in a suspension in operations to deal with this financial crisis. We do not believe that the Legislature intended this result when it enacted AB 32, that the Governor intended this result when he signed AB 32, that the ARB Board intended this result when they adopted the AB 32 Scoping Plan or that ARB staff intended this result when the developed or proposed the California Cap and Trade program. (HDPP1)

> **Response**: We responded to most of HDPP’s comments in the first part of the section. We did not adopt HDPP’s proposed solution involving allocation of allowances directly to independent power producers, because we prefer our approach described above, which offers a variety of solutions appropriate for particular long-term contracts or groups of similar contracts. We did not add the requested language to the Board resolution or to adopt language to provide direct allocations to independent energy generators. However, we will continue to work with such generators on options to satisfy their concerns.
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> For the HDPP power plants specifically, the contract terms of concern are only an issue through 2012. We modified section 95856 and the definition of “compliance period” in section 95802(a) such that there is no compliance obligation until 2013. HDDP will not need allowances for 2012 emissions.

I-128. (multiple comments)
Comment: Calpine proposes the following revisions, which are largely based upon the provisions concerning long-term contract generators appearing within proposed federal climate change legislation and regulations implementing RGGI. Modify section 95802(a) as follows:

(111) “Long Term Contract" means a sales or tolling agreement governing the sale of electricity and/or useful thermal energy from an electric generating facility or cogeneration facility at a price (whether a fixed price or price formula) that does not allow for recovery of the costs of compliance with this regulation and that is at least five (5) years in duration, provided that such agreements are not between entities that were affiliates of one another at the time at which the agreement(s) were entered into.

(112) “Long-Term Contract Generator” means a covered entity which is not an electric distribution utility and which operates an electric generating facility or cogeneration facility pursuant to one or more long-term contracts. (CALPINE1, CALPINE2)

Comment: Modify Section 95802(a)(153) as follows:

(153). "Pre-AB 32 Power Purchase Agreement" means a power purchase agreement between the owner and/or operator of an electrical generating facility and an electric distribution utility for the sale of electricity that does not provide the owner and/or operator of the electrical generating facility with a reasonable opportunity to incorporate the full cost of regulations governing emissions of greenhouse gases. A power purchase agreement qualifies as a "Pre-AB 32 Power Purchase Agreement" where:

a. The power purchase agreement was executed on or before December 31, 2006, for a term greater than five (5) years.

b. The owner and/or operator of the electrical generating facility is a covered entity, but does not qualify as an electrical distribution utility.

c. The executed power purchase agreement does not allow the electrical generating facility to incorporate the full cost of regulations governing emissions of greenhouse gases into the price it charges the electrical distribution utility for electricity.

d. A power purchase agreement shall no longer qualify as a "Pre-AB 32 Power Purchase Agreement" if, after the effective date of this article, it expires or terminates.

e. The fact that a power purchase agreement includes a change in law or regulation provision, or a force majeure provision, shall not disqualify a power purchase agreement from being a "Pre-AB 32 Power Purchase Agreement" unless both parties to the power purchase agreement agree that such a provision entitles the owner and/or operator of the electrical generating facility to recover the cost of complying with regulations governing emissions of greenhouse gases. (GWFPS1)

Response: We did not add these definitions in section 95802(a) because they are not necessary, due to the approach we took to assess options for dealing with long-term contract issues on a case-by-case or categorical basis. Our approach to long-term contract issues is described at the beginning of this section.

Consignment Auction

I-129. Comment: Option for publicly-owned utilities to direct allowances to either auction by consignment or simple compliance provides flexibility but carries risk. Section 95982 (b)(2) states that publicly-owned electric distribution utilities must inform the Executive Officer at least 90 days prior to receiving annual allowances what portion of the allowances should be placed in the utility’s compliance account to be used only for compliance, and the utility’s limited use holding account to be consigned for auction. While SMUD appreciates the flexibility provided to publicly-owned utilities to choose to apply their allowance allocation to compliance without the price risk inherent in allowance auctions, we see other risks in this approach that we believe ARB should carefully weigh prior to adoption. These risks include the possibility that reduced auction participation by some public entities will increase allowance prices and price volatility because of reduced participation. In addition, since the provisions of 95982(d) would no longer apply to allowance value that is reflected in the allowances placed in an entity's compliance account, there is the potential for reduced revenues dedicated to AB 32 purposes. This may serve to increase allowance prices in the long run if such reduction in specifically dedicated revenues leads to fewer investments in energy efficiency and renewables. (SMUD1)

> **Response:** Section 95892 was strengthened to require electrical distribution utilities to use allowance value (not simply auction revenue) for the benefit of ratepayers, consistent with the goals of AB 32. ARB explains why all utilities should not be required to consign their allowances for auction based on the discussion starting on page II-30 and the rationale starting on page IX-61 of the Staff Report.
>
> We do not agree with the implication that a direct allocation will lead to higher and more volatile auction prices. Several POU representatives have indicated that they would pursue a buy-as-you-go approach to the auction, in which they purchase allowances at auction as close in time as possible to when they incur an obligation. To implement this strategy, POUs would bid high for the number of allowances they need. For this reason staff does not believe that the POUs will be setting the auction settlement price. That will instead be done by entities following more speculative purchase strategies. These would be entities that are willing to run the risk of not acquiring allowances at an auction in order to maximize profits.
>
> If utilities must consign the allowances, the utilities would have to use ratepayer funds to purchase them back at auction for compliance or for transfer to a JPA. The net effect of this, together with the small share of the sector in overall compliance, suggests that the magnitude of the effect suggested by the comment would be small.

I-130. Comment: Clarification is required on the timing of auctions given annual distribution of allowances. Subarticle 10 lays out the format and timing of quarterly auctions and allowance distributions. While one quarter of the annual allowances remaining pursuant to section 95870(f) will be auctioned in each quarterly auction, these amounts may be significantly fewer than the allowances distributed under section 95870 (c) to electric distribution utilities and consigned to auction under 95892(c). While it is not clear when utilities that receive such allowances must designate them for auction, section 95910(d)(4) makes clear that these latter allowances will not be included in an auction unless designated for such at least 60 days prior to the auction. Since these allowances are provided to utility distribution companies on or before January 15 of each year (section95870(c)), it seems clear that the allowances provided in each year cannot be included in the first quarterly auction. This may or may not be what ARB intends, but it would imply that the first quarterly auction may have significantly fewer allowances than other quarterly auctions, and some degree of clarification on this timing is desirable. (SMUD1)

> **Response:** We modified sections 958910 and 95870 to clarify the format and timing of auctions and allowance distributions.

I-131. Comment: Insufficient bids for allowances consigned to auction should be sold proportionately, rather than in equal amounts for each entity. Section 95911(b)(3)(B) states that when there are insufficient bids to fully sell all of the allowances that have been consigned to auction, the auction operator will sell an equal number of allowances from each consigning entity. It is appropriate to proportion the allowance sales in this event, but SMUD contends that a proportionate sale of allowances rather than an equal number for each entity is more fair. If entity A consigns 900 allowances for sale and entity B consigns 100, then it is more fair that the auction administrator sell 90 percent of the allowances for entity A and 10 percent for entity B, rather than an equal number for each. (SMUD1)

> **Response:** We agree and modified section 95911(b)(3)(B) as requested.

I-132. Comment: The other implication of auctioning allowances is that the proceeds of the auction that are paid by third parties (such as independent generators, industrial users of fossil fuels and importers of electricity) will be rebated to electric utility customers. These covered entities that are not utilities will be paying for allowances and the benefits will flow to the smaller customers of the IOUs. Meanwhile, the customers of these third party entities will bear higher prices. It is not apparent from the staff explanation of the Proposed Rule that this shift in revenues from other regulated entities to electric utility ratepayers was anticipated or understood. (HOR)

> **Response:** We modified section 95892(a) to require that the benefits (the auction revenue that flows through utilities) be used exclusively for the benefit of retail ratepayers of each utility. Third party entities that are EITEs receive a direct allocation of allowances based on product or energy benchmarking methodology. We expect utilities to pass through carbon costs in their rates, and to compensate all of their customers with allowance value through rebates or other means. Ultimately, as free allocation of allowances is reduced, EITEs will pass through carbon costs in their products, creating the price signal that is the point of a cap-and-trade system. Utility ratepayers include almost all Californians without exception. Because they bear costs both for greenhouse gas (GHG) emissions from electricity production and a separately mandated cost for the renewable portfolio standard, it is important to protect ratepayers from the full cost of both programs.

I-133. Comment: An auction is not good policy either for IOUs or POUs. First, it is unfair to impose a cost immediately for continuing to conduct activities that are now currently lawful and not taxed. Auctioning of allowances serves no legitimate purpose under
AB 32. An auction does not reduce emissions, but (as implemented by ARB) merely serves to move the source of emissions from one group to another. (HOR)

> **Response:** We disagree. Requiring allowances serves to internalize the environmental costs of GHG emissions. Investor-owned utilities (IOUs) will consign their allowances at auction in order to ensure that independent generators have equal access to allowances. The value of those allowances, in the form of auction proceeds, is required to be used for ratepayer benefit. Therefore, utilities consider the emissions intensity of the electricity they purchase and ratepayers are compensated for the carbon costs associated with the electricity. The allocation mechanism for the electricity sector fully compensates ratepayers for the cost of the cap-and-trade program.

I-134. Comment: POUs are not required to purchase allowances because it is politically unpopular to impose such costs on the "public." The distinction made between IOUs and POUs has no apparent basis in AB 32, and fails the requirement under AB 32 to be "equitable." Neither IOUs nor POUs should be required to purchase allowances at auction. Why are POUs not required to purchase allowances at auction? If an auction makes sense for IOUs, then it makes sense for POUs. An auction imposes a cost of carbon that creates a disincentive to emit greenhouse gases. If that is good for IOUs, it should be good for POUs. (HOR)

> **Response:** Publicly owned utilities (POUs) are not required to purchase allowances because they typically own their electricity generation. IOUs compete in an open market for electricity with their own generation and that of third party generators. In order to ensure that independent generators have equal access to allowances, IOUs are required to auction their allowances. We anticipate that they will purchase what they need for their own compliance and likely will purchase allowances for the compliance of generators from which they purchase electricity. POUs argued that, since they own most of their generation, being required to consign their allocations would be akin to requiring them to sell and repurchase their own allowances. In all cases, the price of carbon is what creates a disincentive to emit GHGs. Whether auctioned or not, the price of carbon affects decisions to emit. Even though POUs are not required to consign allocations, they are required to use that value for ratepayer benefit and no other purpose. This is equitable with the requirements on the IOUs.

J. ENFORCEMENT

This section includes comments and responses concerning the enforcement provisions in the regulation, including but not limited to sections 95857 and 96010–96013. The major topic concerns penalties for non-compliance, with sub-topics of the level of penalties, layering of penalties with the Mandatory Reporting Regulation, allowed compliance instruments for payment of penalties, the timing of auctions relative to surrender of compliance instruments, and the need to provide flexibility and ensure strong penalties.

Align with Other Programs/Regulations

J-1. Comment: ARB should consult with the Commodity Futures Trading Commission (CFTC) to ensure the regulation is in full alignment with CFTC regulations that are being developed for natural gas and power markets as part of Title VII of the Dodd-Frank Act. On November 26, 2010, CFTC published a solicitation for public input regarding the oversight of existing and prospective carbon markets to ensure an efficient, secure, and transparent carbon market, including oversight of spot markets and derivative markets in the Federal Register (Vol. 75, No. 227, pg. 72816-17). LADWP recommends that ARB consult with CFTC and review the regulatory proceeding to ensure that the AB 32 cap-and-trade regulation is fully aligned with CFTC regulations moving forward. (LADWP1)

> **Response**: We consulted with technical experts at the CFTC. We will ensure that the cap-and-trade draft regulations are reviewed and aligned with the final CFTC regulations to the extent the CFTC regulations are finalized by October 28, 2011, which is the date that ARB must submit the rulemaking file to the Office of Administrative Law.

Untimely Surrender

J-2. Comment: To increase the impetus for timely and complete compliance, EDF encourages CARB to make the entire untimely surrender obligation be immediately due upon failure to meet the compliance deadline. Although this may be the intent of the rule as written, the phrasing of section 95857(c)(1), is not clear as to what amount is “immediately due.” Is it the entire untimely surrender obligation or just the portion that represents the excess emissions? Accordingly, section 95857(c)(1) should be amended to clarify that it refers to the untimely surrender obligation and refers to the entirety of the amount. (EDF1)

> **Response:** We do not intend to collect the entire obligation “immediately.” New section 95857(b)(6) allows the passage of one auction and one allowance price containment reserve sale before the untimely surrender obligation is due. This ensures that covered entities have sources of allowances other than the secondary market before the untimely surrender obligation is due. This change was made in response to stakeholder comments that having the compliance

instruments due within the time originally allotted would adversely affect the market.

J-3. Comment: Applicability of the untimely surrender obligation should not apply to emissions subject to appeal and under review by the Executive Officer. LADWP recommends that an appeal process be included in the regulation for cases where there may be a difference of opinion between the covered entity and the verifier related to the technical calculation of a compliance obligation. In order to avoid undue penalties while an appeal is being reviewed by the Executive Officer, modify section 95857(a)(3) as follows:

(3) The compliance obligation for untimely surrender shall not apply to a covered entity or opt-in covered entity for emissions that are the subject of a written appeal submitted to the Executive Officer while that appeal is under review and consideration. (LADWP1)

Response: We do not believe that an appeal process that is related to the calculation of compliance instruments required for surrender is necessary. The number of compliance instruments for any entity is calculated based on the emissions that the entity reported pursuant to the MRR that receive a positive or qualified positive verification statement. The MRR provides an appeal process for any entity that receives an adverse verification statement. However, that appeal would not affect the calculation in this regulation. The MRR provides that the appeal of a verifier's statement will be concluded before the surrender obligation is calculated. Therefore, there is no need for a separate appellate process in the cap-and-trade program. Moreover, adding additional procedural steps and delays would add costs and market uncertainty.

Offsets

J-4. (multiple comments)
Comment: In order to ensure that the verifiers meet these standards, the program needs to provide for CARB to regularly conduct disinterested audits of offsets, offset registries, and verifiers, and to decertify as necessary. Requiring an independent reviewer pursuant to section 95977(e)—who may be an employee of the verifier—does not meet this purpose. As written, it is uncertain whether CARB has clearly set up a process that minimizes this potential conflict of interest, and should therefore be clarified. (EDF1)

Comment: CARB set up a process as rigorous as the one required for the offset project registries in section 95987 to avoid attracting lower quality offsets and verifiers with conflicts of interest. Ultimately, CARB should make explicit that verifiers and registries that act in bad faith or repeatedly have Qualified Offset Verification Statements reversed should be subject to decertification for good cause as authorized to the Executive Officer under section 95132(d). (EDF1)

Comment: There also should be a means for third parties to challenge verifiers' certifications. (EDF1)

> **Response:** We do not believe that the recommended changes are necessary. ARB's review of verifiers' certifications will be conducted according to the standards set forth in the regulation. We have full authority to administer and provide oversight of the offset verification program. This ensures consistency across verifications and certainty that the verification services meet the requirements of the regulation. If a third party has specific concerns related to an offset project verification, they should share those with ARB. The concept of independent review within the verification body is consistent with international best practices and does not substitute for an ARB audit or review.

J-5. Comment: CARB should clarify what it will do when 1) offsets are found to be inappropriate or are reversed and 2) verifiers fail to perform their jobs as required. (EDF1)

> **Response:** We added new text to section 95985 to provide clarity on the handling of offset invalidations, including notification, determinations, invalidations, and replacement of invalidation offsets for both sequestration and non-sequestration projects. We modified section 95983 to clarify how reversals for sequestration projects will be handled. We will pursue the appropriate remedy as provided by statute against verifiers that do not adequately perform verification services. However, we anticipate that many of the disputes related to inadequate verification services will be settled by contracts between the offset project operator and the verifier.

Offset Buyer Liability

J-6. Comment: CARB should make clear that it will deny requests for offset credits that fail to meet these criteria and will invalidate any previously issued credits that are discovered to not meet these criteria. (EDF1)

> **Response:** The regulation sets forth the requirements to qualify credits as ARB offset credits. If it is later determined that the offset credits do not meet ARB's criteria, those credits will be revoked in accordance with section 95983 of the regulation.

ARB Jurisdiction

J-7. Comment: The assertion of jurisdiction should be tailored to circumstances in which an entity has a compliance obligation under the proposed regulation. The proposed regulation provides that the purchase or holding of a compliance instrument or receipt of proceeds from the sale of a compliance instrument constitutes consent to the jurisdiction of California and the ARB. Jurisdiction should not extend to circumstances where California links with another jurisdiction and a compliance instrument originating in California is traded in another jurisdiction. For example, if an entity sells an allowance originally created in California to another entity subject to a linked cap-and-trade compliance program, that transaction should not be subject to California law; the mere act of transacting does not in itself warrant jurisdictional claim. In other words, when the compliance instrument is used to satisfy another state's compliance obligation, the entity retiring the compliance instrument should only be subject to the jurisdiction of that state. (PACIFICOR1)

> **Response:** The commenter raises issues related to linkage agreements with other jurisdictions. ARB anticipates that these issues will be finalized during the negotiations of linkage agreements. However, ARB currently is the only jurisdiction in which ARB offset credits will be accepted, so the point made by the commenter is moot at this time.

J-8. Comment: PacifiCorp recommends that the ARB should not assert jurisdiction whenever an entity uses a compliance instrument that was created in California. Specifically, the assertion of jurisdiction in section 96010(b) and (c) should be limited to transactions in California. (PACIFICOR1)

> **Response:** We do not agree. If an offset project operator applies for credits in California's cap-and-trade program, regardless of the operator's location, it is subject to California's jurisdiction. Additionally, if ARB issues an offset credit, ARB must maintain jurisdiction over the use of that offset credit, as it is only authorized for use in ARB's system.

Robust Enforcement

J-9. (multiple comments)
Comment: Make the cap strong and universal. Put solid money into enforcement and oversight measures. Apply stringent rules of compliance for all GHG emitters. (LANGE)

Comment: If California is going to establish a market in greenhouse gas emissions, strict transparency and enforcement requirements are absolutely essential. ARB must vigilantly use transparency and enforcement tools to make sure that the public interest is protected from the self-dealing, fraud, and windfall profits that have plagued other markets. (SIERRACLUBCA4)

> **Response:** We intend to make the operation of the cap-and-trade program as transparent as possible. However, we must also balance the protection of confidential business information to ensure that covered entities do not gain an unfair advantage or obtain knowledge that would allow them to collude on the prices of commodities.

J-10. Comment: The cap part of the Cap and Trade program must be solidly enforceable here in California. All contributory industries are dragging their feet in making necessary changes to how they do business, hoping to avoid having to make the tough decisions that are inevitable and overdue. A strictly enforceable Cap on greenhouse emissions in California must be an example to the rest of the Nation that we can't be lazy and greedy anymore if we truly want to survive. (GOFF)

> **Response:** We understand that many stakeholders are concerned about the possibility that business-as-usual practices will continue. However, a firm regional cap with strong reporting and enforcement rules will provide a high degree of environmental certainty that emissions will not exceed targeted levels. As part of the cap-and-trade program, major sources of emissions will be subject to an emission cap which must be met, regardless of growth. Inclusion of strong reporting and enforcement requirements in this program also provide certainty in achieving the 2020 cap. In addition, the largest sectors will also be subject to other recommended measures, which provide significant cost-effective reductions and complement the cap-and-trade program. Further, the regulation includes strict rules for reporting emissions and trades, with substantial penalties for violations. Transparency in the trading process is important to avoid market manipulation.

Penalties

Clarification Needed

J-11. Comment: This rule sets forth a multitude of violations that are established if trading is manipulated, fraudulent, or based on misinformation or attempts to fix price. However, the consequences for such behavior are unclear. Does a fraudulent trade result in a one-day violation of the Health and Safety Code? Without a clear definition of the number of days of violation or counts associated with these acts, there will be grossly inadequate penalties associated with violations that could result in huge profits. (CAPCOA1, CAPCOA2)

> **Response:** Apart from the Health and Safety Code, laws addressing unfair business practices, antitrust, securities trading, commodities trading, and fraud may apply to fraudulent trading practices, and could be enforced by a variety of state and federal agencies. Health and Safety Code section 38580 also provides for penalties based on “any violation” (in the singular) of the regulation. A fraudulent transaction involving one compliance instrument or offset credit would constitute a violation of the cap-and-trade regulation; a fraudulent transaction involving multiple instruments or credits would constitute multiple violations of the regulation, each subject to significant penalties under section 38580.

Executive Officer Actions on Holding Accounts

J-12. Comment: It is not appropriate to allow the Executive Officer to restrict an entity’s holding account if ARB alleges an entity is determined to be in violation of provisions of this article. This provision allows the ARB substantial opportunity to force reconciliation instead of following accepted dispute resolution processes during an enforcement matter when an entity disagrees that there is non-compliance. For example in the situation where there is a dispute that insufficient allowances were retired ARB could "restrict" the entity's allowance account potentially causing additional future noncompliance because the account cannot be accessed. Section 96011 is neither appropriate nor productive and should be removed from the regulation. (SEMPRA1)

> **Response:** We do not agree. The cap-and-trade regulation does not have a contested surrender provision because an entity's surrender obligation is based on emissions that the entity reported to ARB pursuant to the MRR. The regulation is written to provide the Executive Officer flexibility in how to respond to an issue that results in a violation of the regulatory requirements. The example provided is not explicitly stated in the regulation, so that specific concern is misplaced.

J-13. Comment: As proposed, section 96011 would allow suspension, revocation or restriction of holding accounts and Executive Orders when an entity is determined to be in violation of any provision of the cap-and-trade rule. These provisions do not specify whether the Executive Officer makes that determination, the basis for the determination (i.e., issuance of Notice of Violation (NOV), settlement, court finding), or how and when a suspension, revocation or restriction is lifted. PG&E suggests that this section be improved by adding further clarity and specific criteria with regard to determining whether a violation occurred, and for the duration and removal of any suspension, revocation or restriction. For example, "determined to be in violation" should require that an NOV has been issued. Once an alleged violation is resolved (whether through a settlement, court action, or otherwise), any suspension, revocation or restriction should be lifted except where unusual circumstances justify continuing the suspension, revocation or restriction. (PGE1)

> **Response:** Section 96011 gives the Executive Officer authority and discretion to determine whether to invoke the remedies set forth in that section. Implicit in that authority is the ability to lift a suspension, revocation, or restriction. At this time, in the absence of particular facts and circumstances, it would not be appropriate to prescribe detailed procedures or a particular duration for those remedies.

Consideration of Circumstances

J-14. Comment: The Utilities acknowledge that compliance is a critical component of any cap-and-trade program and understand that CARB, under AB 32, is directed to use existing penalty provisions. Health and Safety Code section 38580 references penalty provisions in Article 3 of Chapter 4 of Part 4, commencing with section 42400, and Chapter 1.5 of Part 5, commencing with section 43025, of Division 26. CARB is given authority to develop a method to convert a violation into the number of days in violation, where appropriate (section 38350(b)(3)). Designated maximum criminal and civil penalties are then set forth for each type of violation. In each case a list of relevant circumstances are required to be considered in setting the level and amount of penalty. (see Health and Safety Code section 42400.8.) The Utilities believe it is critical to the protection of the State's electric ratepayers that such circumstances be expressly included in the proposed regulation's penalty provisions. The Utilities want to ensure fairness in determining compliance and recognition of the numerous extenuating circumstances that can affect an entity's ability to comply. We do believe that it is necessary to ensure that any penalty to be imposed is proportionate and relative to the nature of the non-compliance. The circumstances of the non-compliance as well as existing barriers to the compliance must be taken into account. The Utilities believe that attention has to be paid to circumstances outside the control of utilities such as the availability of transmission, the availability of low emitting technologies that are feasibly implemented, the shifting of emissions from other sectors (such as through the electrification of vehicles), the responsibility of electric utilities to maintain grid reliability, the cost effectiveness of available compliance tools, and other mitigating circumstances such as unusual weather, hydro and economic conditions. Thus, a provision for dealing with extenuating and unforeseen circumstances must be included in any program design. Modify section 96013 as follows:

> Penalties may be assessed pursuant to Health and Safety Code section 38580 for any violation of this article. *In determining whether to assess a penalty and any amount assessed, the Executive Officer shall take into consideration all relevant circumstances, including but not limited to those identified in Health and Safety Code section 42400.8.* (MID1)
>
> **Response:** The suggested language incorrectly assumes that the Executive Officer can unilaterally impose penalties. That is not the case. Health and Safety Code section 38580 commands that ARB enforce AB 32 regulations. Under the Health and Safety Code, ARB can *seek* penalties, but only an administrative law judge or court can impose penalties. ARB's authority does not extend to determining final penalty amounts. In many of its enforcement actions, ARB and the entity from whom ARB is seeking penalties will reach a mutual settlement agreement, including an agreed upon penalty amount. ARB may seek penalties in a judicial action, in which the ultimate penalty amount is determined by a neutral judge, based on the statutory penalty structure. In no instance is ARB able to unilaterally assign a penalty amount on a violator. Nevertheless, we modified section 96013 to include a reference to Health and Safety Code section 42403(b); in seeking a penalty, ARB will consider all relevant circumstances. Section 42403 is the appropriate reference because it relates to penalty determinations in civil actions, the kind of enforcement action that ARB can initiate.

J-15. Comment: Dow recommends that ARB revise section 96014 of the proposed regulation to ensure that penalties for cap-and-trade violations are commensurate with the scope and severity of the violation and potential environmental harm, and are consistent with penalties for other stationary source violations. Penalties should be just high enough to induce compliance. Sections 96014(a) and (b) specify that violations for failure to surrender the required number of compliance instruments are a separate violation for each missing compliance instrument, and are a separate violation for each day after the specified compliance date that a required compliance instrument has not been surrendered. Since each "compliance instrument" is equivalent to one metric ton of GHGs (proposed section 95802(a)(36)), these subsections together result in a "per metric ton per day" penalty approach. (DOWCHEM1)

> **Response:** ARB agrees that penalties should be high enough to deter violations, but does not believe it is possible to determine what penalty will be "just high enough to induce compliance," particularly before knowing the actual circumstances of a particular violation. We modified section 96013 to include a reference to Health and Safety Code section 42403(b), to consider all relevant circumstances related to assessing a penalty. Section 42403 is appropriate because it relates to penalty determinations in civil actions, which is what an ARB enforcement action would be considered. Additionally, section 96014 has been modified to calculate penalties on late surrendered compliance instruments every 45 days instead of per day. We examined the possible penalties and found that the "per ton per day" approach could theoretically result in penalties that were too high.

Provide Flexibility Before 4:1 Untimely Surrender

J-16. (multiple comments)
Comment: The proposed regulation should provide greater flexibility in meeting the compliance obligations by providing notice and an opportunity to cure a compliance shortfall before ARB assesses the 4:1 penalty. Under the proposed regulation, a regulated entity will be penalized at a 4:1 ratio for every emissions allowance it fails to retire under its triennial or annual compliance obligations. The regulated entity would be required to retire four times the allowances within 30 days of the triennial or annual compliance deadline. This penalty could be unduly onerous in situations where a regulated entity was either unable to procure a sufficient amount of allowances (despite diligent efforts) or where a shortfall resulted from unintentional accounting errors. The 4:1 penalty should only take effect after ARB provides notice and a reasonable opportunity to cure the shortfall. This is particularly important for the electric sector, where gross emissions are a function of electric demand that is not entirely within the direct control of the utility, but rather can be an outcome under their obligation to serve customers. (PACIFICOR1)

Comment: CARB should provide flexibility in achieving compliance obligations. In accordance with section 95857(b)(2), p. A-72), a covered entity will be penalized at a 4:1 ratio if it fails to retire sufficient allowances consistent with its triennial or annual compliance obligation. The regulated entity would be required to retire four times the allowances within 30 days of the triennial or annual compliance deadline. Praxair is concerned that this penalty structure will be unduly burdensome in situations in which a regulated entity was either unable to procure a sufficient amount of allowances (despite diligent efforts) or the shortfall resulted from unintentional accounting errors. The 4:1

penalty should only take effect after CARB provides notice and a reasonable opportunity to cure the shortfall. (PRAXAIR)

> **Response:** The cap-and-trade regulation provides a reasonable opportunity to cure shortfalls; the original unsurrendered compliance obligation and the additional surrender obligation are required to be surrendered by five days after the latter of an auction or allowance price containment reserve sale. To the extent that the commenters recommend a "notice-to-comply" approach in lieu of enforcing the regulation as it is written, we note that notice-to-comply programs do not promote full compliance with the law. These programs send the wrong signal—that no one need comply with the law until caught in violation. Such programs unfairly disadvantage businesses that comply with the regulatory requirements before an enforcement action begins. Finally, notice-to-comply programs also require much greater enforcement resources than ARB has at its disposal.

Untimely Surrender: Excessive Penalties

J-17. Comment: The Board should direct staff to make appropriate revisions to the enforcement provisions to provide that covered entities would not be subject to both excess emission penalties and civil and criminal penalties under HSC. (CCC, MAZOWITA)

> **Response:** By statute, the same conduct is subject to either civil or criminal penalties, but not both. See Health and Safety Code section 42400.7. The additional surrender obligation is not a penalty. We modified the regulations to indicate that no penalties will accrue until five days after both an auction and an allowance price containment reserve sale occur.

J-18. Comment: The Board should direct the staff to make appropriate revisions to the enforcement provisions to provide that civil and criminal penalties would not apply to each compliance instrument that has not been surrendered. (CCC, MAZOWITA)

> **Response:** It is not clear what the commenter is suggesting. However, penalties will be calculated beginning on the fifth day after both an auction and an allowance price containment reserve sale, and will accrue every 45 days on each compliance instrument not surrendered, including any not surrendered as a result of the additional surrender obligation.

J-19. Comment: Pursuant to section 95857(c), the obligation to surrender allowances for untimely surrender is immediately due, and penalties can be pursued if the Covered Entity does not surrender sufficient allowances to meet this obligation within 30 days. NCPA recommends that the provisions of the proposed regulation be clarified to ensure that a Covered Entity that meets all of the obligations of section 95857 during the 30-day cure period is not also subject to additional penalties under the provisions of sections 96013 and 96014. (NCPA1)

Response: We agree. The cap-and-trade regulation requires that the original unsurrendered compliance obligation and the additional surrender obligation be surrendered by five days after the latter of an auction or allowance price containment reserve sale.

J-20.
Comment: DWR, a public agency, may face fiscal difficulties and cash flow problems in purchasing high value allowances due to the background of public budgeting and revenue collection. We request that ARB reduce the penalty for noncompliance as one way to reduce this threat. (DWR)

Response: In seeking any penalty, ARB would consider compliance efforts and compliance challenges that any alleged violator faced among the circumstances required to be considered under section 96013 of the rule and Health and Safety Code section 42403(b).

J-21. Comment: The severity of the penalty for untimely surrender of allowances should be re-evaluated. Subjecting an entity to both a monetary penalty and the requirement to surrender additional allowances is a double penalty for the same violation. In addition, the calculation methodology for monetary penalties should be limited. The current method, based on a per ton, per day violation, could generate disproportionate penalty amounts. As an example, a $10,000 fine for Paramount has a much greater impact than the same penalty assessed against a major oil company. (PMTPETRO1)

Response: The additional surrender obligation is not a penalty. Regarding the "per-ton, per-day" portion of the comment, ARB notes that in the second 15-day changes to the regulation we revised the method of calculating penalties in section 96014(b) so that there is a separate violation for every 45-day period that passes without the obligation being paid, rather than every day. This change dramatically slows the rate at which penalties may accumulate. See also the response to Comment J-15.

Regarding the commenter's concern that the "per-ton" aspect of Section 96014(a) could yield "disproportionate penalties," we note that 96014(a) identifies one compliance instrument as the unit of violation because the compliance instrument is the basic unit on which the regulation is based, and corresponds to the basic reporting unit under the MRR. In the event that an enterprise fails to surrender required compliance instruments, the number of violations and the potential penalty will always be proportional to the magnitude of the noncompliance, regardless of the enterprise's size. Defining a violation in terms of a compliance instrument is a necessary deterrent because failing to surrender an instrument as required would confer a direct economic benefit on the violator. Failing to surrender compliance instruments also threatens the integrity of the emissions cap. To discourage this type of behavior, the penalty must do more than merely take away the economic benefit gained by the violator. The deterrent effect of proportional but potentially large penalties is necessary to accomplish the goals of the cap-and-trade regulation.

Defining a violation based on a per-unit value is consistent with other ARB regulations that define penalties proportional to the conduct. The definition is consistent with the Global Warming Solutions Act's intent that regulations be enforceable, be enforced, and result in significant penalties. (See Health and Safety Code sections 38560.5 subd. (d) [enforceable rules], 38562 subd. (d)(1) [enforceable reductions], 38580, subd. (a) [ARB shall enforce], and 38580(b) [penalties].) Moreover, Health and Safety Code section 38580(b)(3) authorizes ARB to define penalties on a per-unit basis, proportional to the conduct, rather than defining violations purely in terms of days.

J-22. Comment: Requiring additional surrender of allowances above the base surrender obligation as a non-compliance penalty is inappropriate as a matter of good public policy. While the variant currently being considered is superior to a pure "assess and retire" approach, it will still have avoidable, undesirable, adverse impacts. Therefore, we recommend that the penalty for non-compliance be 1) fulfilling the underlying surrender obligation that was not initially met, and 2) an additional monetary penalty. Alternatively, although still in our view a substantially inferior approach, if there is a desire to provide a non-monetary option, in the context of the other parameters of the California program, it might be sensible to allow the "penalty" to be paid in "ex quota" offset credits—that is, using offsets over and above the 8 percent of compliance obligation restriction. (MSCG2)

Response: We do not agree. The additional surrender of allowances is not a penalty, but ensures the environmental integrity of the cap-and-trade program. The regulation has been modified to mitigate some concerns raised by stakeholders. In the second 15-day changes to the regulation we modified section 95857(d) so that three-fourths of the "excess emissions" compliance instruments are placed into the auction account to avoid "tightening" the market for all participants. We also modified section 95857(b)(4) and added new section 95857(b)(5) in the second 15-day changes to the regulation to allow the use of offsets for one-fourth of the "excess emissions," as long as the quantitative usage limit is not violated for the applicable compliance period.

J-23. Comment: The regulation's fourfold penalty for a failure to timely surrender compliance instruments is unwarranted, at least for public agencies. DWR, like most public agencies, never considers ignoring or disobeying the law to be an option. The only scenario in which such a failure is conceivable would be a complete lack of available allowances or an unexpected and extremely unaffordable allowance price. In either case, a fourfold penalty is no remedy. A public agency's failure to meet a legal obligation to surrender allowances would trigger various disclosure requirements along with concomitant adverse consequences to budget planning, water rates, cost allocation, and water contract administration. The inordinately high penalty amount would only exacerbate attempts to remedy such a situation. The regulation should be amended to delete the fourfold penalty for the Department of Water Resources. Modify section 95857 as follows:

> <u>(e) This section does not apply to the Department of Water Resources.</u> (DWR)

> **Response:** ARB does not believe that treating DWR differently from other covered entities regarding its surrender obligation is appropriate.

J-24. Comment: Subsections (a) and (b) of proposed section 96014 specify that violations for failure to surrender the required number of compliance instruments are a separate violation for each missing compliance instrument, and are a separate violation for each day after the specified compliance date that a required compliance instrument has not been surrendered. Since each compliance instrument is equivalent to one metric ton of GHGs (section 95802(a)(36)), these subsections together result in a per metric ton per day penalty approach. Under proposed section 96013, the stationary source penalty authorities of Health and Safety Code sections 42400 et seq. would apply. PG&E does not support ARB's proposal that each missing compliance instrument be considered a separate daily violation. Given the magnitude of stationary source annual GHG emissions, treating each missing compliance instrument as a separate violation for every day the shortfall continues is likely to result in extremely large numbers of violations for each occurrence of a shortfall. Large numbers of violations in turn create the possibility for extremely large penalties. In PG&E's view, the proposed cap-and-trade program should include violation provisions and penalty guidelines that ensure that penalty exposure is consistent with existing stationary source penalty assessments, and total penalty amounts are not unreasonably large because GHG emission rates are large in comparison to emission rates for traditional air pollutants. PG&E recommends the following approach to enforcement for the cap-and-trade program. First, section 95857(b) should be revised to eliminate the four time multiplier for excess emissions resulting from untimely surrender. Instead require surrender of sufficient compliance instruments to make up the shortfall on a 1:1 basis, and impose a requirement for a cash payment of three times the quantity of excess emissions, multiplied by the most recent allowance market price. Second, section 96014(a) and (b) should be revised so that no violation occurs if a compliance shortfall is cured under section 95857 within the 30-day cure period. Failure to cure a shortfall within the 30-day period should be a single violation per day from the end of the 30 days until the shortfall is made up and the cash payment is made. (PGE1)

> **Response:** We disagree with the first recommendation to eliminate the excess emissions obligation in favor of a financial penalty and did not make the recommended change. The excess surrender obligation ensures the environmental integrity of the cap-and-trade program.
>
> We modified the calculation of penalties, although the modification was not accomplished in the manner suggested by the commenter. Specifically, in the second 15-day changes to the regulation, we modified section 96014(b) so that a

> new violation occurs every 45 days that the entity has not cleared its surrender, in order to reduce the rate at which penalties increase. Each allowance not surrendered is still the basis for the penalty. See the response to Comment J-20.

J-25. (multiple comments)
Comment: Enforcement penalties are overly punitive and should be modified. Section 95857 provides for penalties in the event that an entity fails to surrender sufficient compliance instruments. The regulation would require surrender of compliance instrument equal to four times the deficient quantity of instruments and additionally subject the entity to penalties under the Health and Safety Code. Section 96013 further provides that each deficient compliance instrument will be considered a separate violation and that each day thereafter will also be considered a separate violation. WPTF has a number of concerns about these penalty provisions. First, the application of the terms of the Health and Safety Code has the potential to quickly result in excessive penalties for a single violation. The same concerns were raised by stakeholders in regard to similar provisions in the regulation for the Renewable Energy Standard, and as a result, the Board directed their modification. WPTF requests that the cap and trade regulation also be modified to address the excessive potential of these penalties. (WPTF)

Comment: The severity of the penalty for untimely surrender of allowances should be re-evaluated and a monetary penalty beyond the first allowance should replace the surrender of additional allowances. A 3:1 penalty is more appropriate. To require the submittal of the penalty in additional allowances tightens the market and penalizes all market participants. The regulation requires clarification on whether untimely submittal would result in daily health and safety code violations and penalties beyond the 3:1 (or 4:1) submittal. (BP)

Comment: Treating each individual compliance instrument not surrendered, as well as each day each instrument is not surrendered as separate violations could likely lead to penalties that go beyond incenting compliance and would create unnecessary roadblocks to the achievement of AB 32 goals. This is particularly true in light of the proposals for annual compliance obligations. The Utilities have participated in discussions regarding enforcement provisions in CARB's proposed Renewable Electricity Standard regulations, and support what the Utilities understand to be the direction staff is recommending in that arena. We believe a similar approach could be employed in the proposed Cap-and-Trade regulation. Modify section 96014 as follows:

> (a) If a covered entity fails to surrender a sufficient number of compliance instruments to meet its compliance obligation as specified in sections 95856 or 95857 there is a separate violation of this Article for ~~each required compliance instrument that has not been surrendered.~~
> ~~(b) There is a separate violation for each day or portion thereof after the compliance~~ <u>surrender</u> ~~date that~~ each required compliance instrument <u>that</u> has not been surrendered.

(b) For each six month period after the surrender date, there is an additional, separate violation of this Article for each required compliance instrument that has not been surrendered.
(c) ~~Each day or portion thereof in which any other violation of this Article occurs is a separate offense~~ In determining whether to assess a penalty and any amount assessed, all relevant circumstances shall be considered. (MID1)

Response: The additional surrender obligation is not a penalty. See also the responses to Comments J-15, J-20, and J-23.

J-26. Comment: The enforcement provisions must be developed and administered in a way that does not adversely affect a Covered Entity's ability to comply with the regulation going forward. Penalties must be assessed consistent with the principles of malfeasance and gross negligence, and mitigating factors, including programmatic difficulties and sector-related constraints, must be carefully and fully reviewed by the Executive Officer and CARB before penalties are assessed. NCPA has worked closely with CARB staff, the electric utilities, and other stakeholders as part of the Renewable Electricity Standard (RES) Working Group, specifically discussing the appropriate approach for enforcement and penalties. The RES Working Group has recommended a balance with regard to the imposition of "daily penalties," that recognizes that meeting an annual compliance obligation of the nature created in the proposed regulation is somewhat unique in several respects, and accordingly recommends that the "daily penalty" be calculated using a six month period. Consistent with this methodology, NCPA recommends the following revisions. Modify section 96013 and 96014(b) and (c) as follows:

Penalties. Penalties may be assessed pursuant to Health and Safety Code section 38580 for any violation of this article. In determining whether to assess a penalty and any amount assessed, all relevant circumstances shall be considered.

(b) There is a separate violation for each ~~day~~ six-month period or portion thereof after the compliance date that each required compliance instrument has not been surrendered.
(c) Each ~~day~~ six-month period or portion thereof in which any other violation of this Article occurs is a separate offense. (NCPA1)

Response: ARB cannot unilaterally assess penalties. In seeking any penalty, ARB considers all relevant circumstances, including those suggested by the commenter. We included a variation of the suggested language in section 96013, and modified section 96014 to allow 45 days (not the six months suggested by the commenter) for each offense to accrue.

J-27. Comment: Currently, the proposed regulation's penalty provisions are excessive, unbounded, and vague. SCE recommends that CARB clarify its penalty provisions. Section 95857(b) of the proposed regulation requires that a covered entity that has surrendered insufficient compliance instruments in a timely manner (known in the proposed regulation as “excess emissions”) is penalized with a new compliance obligation of four times the excess emissions. A penalty of four times the excess emissions is disproportionately punitive. If a compliance entity could not acquire sufficient allowances to surrender for compliance, it is unlikely that it could acquire four times that amount. Moreover, while the regulation allows for borrowing to meet this penalty provision, a penalty of four times the excess emissions implies a 300 percent interest rate to borrow.

Subsection 15 of the proposed regulation establishes additional consequences for violations of the cap-and-trade regulation, including injunctions and other penalties. Under this section, CARB may assess a separate violation for each required compliance instrument that has not been surrendered, as well as a separate violation per day. CARB staff has noted that these violations are unique to the cap-and-trade program. While these provisions represent an improvement in that they establish violations specific to compliance instruments, the penalty provisions simply provide that “penalties may be assessed pursuant to Health and Safety Code section 38580 for any violation of this article.” Section 38580 of the Health and Safety Code codify the enforcement provisions of AB 32. These provisions refer to several other sections of the Health and Safety Code that create criminal, civil, and administrative penalties for emissions violations, including emissions of air contaminants. The provisions include criminal and civil penalties that range from fines of $1,000 to $1,000,000, and up to a year in county jail or state prison per violation. This is a menu of enforcement penalties designed to punish stationary sources for their emissions, and are overly punitive and not readily applicable to the cap-and-trade regulation framework. SCE recommends that CARB revise and clarify the penalty provisions to make them more applicable to the cap-and-trade context. (SCE1)

> **Response:** Section 95857’s additional surrender obligations are not a penalty; they ensure the program’s environmental integrity. Regarding Subarticle 15, see the responses to Comments J-15, J-20, and J-23.

J-28. (multiple comments)
Comment: Clear and effective penalty provisions are essential for the program to achieve emission reductions and deter non-compliance. We commend CARB for the robust and transparent penalty structure proposed in the regulations. Requiring noncompliant entities to surrender a multiple of four compliance instruments within 30 days for every one missed (and only one may be an offset) sends a clear signal that noncompliance will neither be tolerated nor financially advantageous. Tacking on monetary fines that accumulate up to $25,000/day will further deter would-be violators. (NRDC1)

Comment: The recently proposed enforcement provisions that consider failure to report every ton of excess emissions and submittal of inaccurate information as separate violations would potentially result in unwarranted and excessive penalties, relative to other criteria pollutant penalties. CCEEB recommends that the ARB return to the original penalty provisions, which provide the ARB with a mechanism to deal with fraud and intentional actions while managing unintentional errors in fair manner. (CCEEB1)

> **Response:** See the responses to Comments J-15, J-20, J-23, and J-25.

Untimely Surrender Penalty: Market Impacts

J-29. Comment: If an entity is late in their surrender of allowances, the penalty will be that they have to purchase three additional allowances for every one that they were unable to surrender. This will shorten the supply available in the auction. (AGCOALITION)

> **Response:** Section 95857's additional surrender obligations are not a penalty; they ensure the program's environmental integrity because it is a strong deterrent to noncompliance. We added new section 95857(b)(6), which states that the additional allowances are not due until five days after the next auction and allowance price containment reserve sale, whichever is later. We also modified section 95857(d) to return allowances submitted to cover an untimely surrender back to the auction account, so as not to affect supply for other market participants.

J-30. Comment: Provide a safety valve penalty option (similar to the federal SO2 program) under which a regulated entity that is simply unable to obtain allowances may achieve compliance after the fact by paying a penalty or implementing other mitigation. Without a backup method of maintaining compliance, the cap and trade system could generate essentially infinite prices for allowances. There needs to be some absolute limit imposed or some other alternative for compliance in view of the fact that allowance shortages will come to light only after the cap is exhausted and allowances are no longer available. (HOR)

> **Response:** We disagree with providing an absolute limit on penalties. However, for each surrender obligation an entity fails to meet, the additional surrender obligation will only apply once. This will limit the number of allowances or ARB offset credits required to bring a covered entity's compliance account current.

J-29. Comment: CCAP recommends additional clarification of compliance and enforcement mechanisms including provisions for the disposition of allowances in relation to insolvency, dissolution or downscaling of covered entities. While the proposed regulation provides a useful 30-day period to cure identified untimely surrenders not otherwise satisfied by section 94857(c)(2-3), it would also be helpful to provide an explicit time frame in which the Executive Officer will assess timely surrender of obligations. (CCAP1)

> **Response:** Section 95856 provides the surrender date. Covered entities will know what their compliance obligations are because those entities will report to

emissions pursuant to MRR. There is no “time frame” to assess whether the compliance instruments have been surrendered. ARB anticipates that the disposition of allowances of an insolvent, dissolved, or downscaled covered entity will be addressed through the appropriate documentation of the covered entity and as required under the reporting elements of the MRR.

J-32. (multiple comments)
Comment: The proposed cap-and-trade rule provides an automatic emissions penalty of four times the “excess emissions” for failure to timely submit the required amount of compliance instruments. See proposed section 95857(b). The proposed rule also allows for a 30-day period to be provided allowing a covered entity time to obtain the compliance instruments needed to correct a shortfall (including the 4x multiplier). See section 95857(c)(4)(6). Dow recommends the following approach to enforcement for the cap-and-trade program. First, section 95857(b) should be revised to eliminate the 4x multiplier for excess emissions resulting from “untimely surrender,” and instead require surrender of sufficient compliance instruments to make up the shortfall on a 1:1 basis, and impose a requirement for a cash payment of twice the quantity of excess emissions, multiplied by the most recent allowance market price. This approach would be sufficient have the same economic impact on the source as the 4x surrender requirement, while avoiding potential adverse market effects resulting from artificially decreased supply of allowances. (DOWCHEM1)

Comment: The excess surrender requirements of section 95857 (Untimely Surrender of Compliance Instruments by a Covered Entity), adversely impact all Covered Entities and not just those that are out of compliance by reducing the number of compliance instruments available for surrender. Such an outcome should be avoided.
NCPA recommends that the proposed regulation be revised to permit allowances to set the value for non-compliance, by requiring the non-complying entity to surrender the required number of allowances plus a payment valued at three times the amount of allowances in the most recent auction. If CARB requires actual allowances to be surrendered in excess of the compliance obligation, then CARB is penalizing all other market participants—particularly those with a compliance obligation—because the allowances will not be available for purchase at that time. This concern is not mitigated by the fact that the allowances will be placed back into the market for two reasons. First, the allowances will come out of the market for some period of time and for Covered Entities seeking to buy allowances during that time period, the demand will be greater as the entity that is trying to meet the out-of-compliance surrender obligation will be purchasing more allowances than what was contemplated in the allowance budget. Secondly, the excess allowances will be placed back into the market, but as currently drafted, these allowances will go into the Reserve Account. That means the allowances will automatically be valued at more than the Auction Reserve Price. Again, this results in increasing the compliance cost for other Covered Entities. If the proposed regulation is not changed to monetize the value of the untimely surrender obligation for noncompliance, the provisions of section 95857(d) should be revised to ensure that the allowances from the excess surrender obligation are placed back into the auction at a non-discriminatory rate that does not adversely impact the remaining Covered Entities.

Accordingly, the three-quarters of allowances used to meet the untimely surrender obligation should either be placed back into the CARB Auction Holding Account (defined in section 95831(c)(2)), or at a minimum, the allowances should be used to repopulate the first tier of the Reserve Account, and not placed into the highest tier, where they will only be available to all other Covered Entities at the highest possible price. Section 95857(d)(2)(A) should be revised accordingly. (NCPA1)

Comment: The regulation proposes that entities that miss the deadline for retiring compliance instruments retire four allowances for every ton of emissions. Not only is this requirement unfair but it penalizes market participants by limiting the number of allowances in the market every time an entity misses its retirement obligation. (CALCHAMBER1)

Comment: CARB proposes that noncompliance should be penalized with a four times multiplier for excess emissions. We believe that the per ton penalty approach proposed by CARB staff is overly punitive. In addition, taking the additional allowances out of the market and putting them in the allowance reserve would make them available for purchase only at the higher reserve price, a bad outcome for remaining innocent market participants. We recommend that a more moderate penalty structure be adopted without taking allowances out of the market. (CMTA1)

Comment: WSPA recommends that ARB revise the enforcement provisions, so that late or insufficient amount of instruments should only be subject to one times penalty. Further, we urge ARB to strongly consider all insufficient instruments that are above one times to be surrendered in the form of a dollar payment for each instrument based on a price equal to the market price at the time the allowance should have been surrendered. While WSPA understands ARB’s need to have appropriate enforcement provisions in place to ensure compliance with meeting the requirements of the C&T Regulation, we believe imposing duplicative penalties for the same offense is unnecessarily stringent. Further, WSPA believes requiring the violator to surrender four times the insufficient amount could potentially penalize others in the market as it will force the early retirement of instruments that could otherwise be available for use by others in the market. (WSPA1)

Comment: The excess emissions obligation is excessive and should be made consistent with other trading programs. The draft regulation indicates that the covered entity's compliance obligation for untimely surrender is calculated as four times the entity's excess emissions (4:1 ratio). This compliance penalty is excessive in comparison to other existing emissions trading programs and may have the unintended consequence of limiting the market further than necessary or appropriate. The RECLAIM and Acid Rain programs require that the amount that the allocation is exceeded be deducted from the next year's allocation on a 1:1 ratio. CARS audits may reveal that some entities need to apply conservative CEMS missing data procedures, which may result in a calculated surrender obligation that is above the entities' actual emissions. Such approach ensures the environmental integrity of the program is not compromised, but does not go so far as to take out of circulation additional allowances that are needed by covered entities in general for compliance. This occurs when ARB transfers three fourths of surrendered allowances to the highest-priced tier in the Allowance Price Containment Reserve Account (the other one fourth is retired). This approach works against other cost containment provisions in the regulation and essentially penalizes all covered entities by restricting allowance supply and driving up the allowances prices. This provision is in addition to financial penalties proposed under section 96013, where penalties may be assessed for any violation, and section 96014, where a separate violation is defined for each day or portion thereof after the compliance date that each required compliance instrument has not been surrendered. If a covered entity has excess emissions of 500 MT for 10 days, it must then surrender 20,000 MT of California allowances [500 MT of GHG emissions x 4 California GHG allowances x 10 days= 20,000 MT of California GHG allowances]. LADWP strongly recommends that the untimely surrender obligation for excess emissions remain consistent with other emissions trading programs with a 1:1 surrender obligation, in which the replaced compliance instrument is permanently retired. Modify section 95857(b) as follows:

> (b)(2) *A covered entity's compliance obligation for untimely surrender is calculated as ~~four times the entities excess emissions~~* <u>equal to the entity's excess emissions</u> (LADWP1)

Comment: The severity of the penalty for untimely surrender of allowances should be re-evaluated. Subjecting an entity to both a monetary penalty and the requirement to surrender additional allowances is a double penalty for the same violation. In addition, the calculation methodology for monetary penalties should be limited. The current method, based on a per ton, per day violation, could generate disproportionate penalty amounts. (WIRA1)

Comment: California's cap-and-trade program departs from the standard practice of imposing monetary penalties, as seen in the US Acid Rain program and the EU ETS, on each ton of excess emissions not covered by allowances in any compliance period. IETA advises against using a non-compliance penalty based on the forced withdrawal of allowances, and instead recommends adopting a more traditional fixed monetary fine similar to those seen in the highly successful US SO2 and NOx emissions markets. A monetary penalty provides price stability in an uncertain market. A monetary penalty does not force the market price to increase. Under the current draft regulations, three allowances are to be placed in the APCR account, which would be available for purchase should that account be activated. It is likely to push prices up, as more allowances will only be available from the price containment reserve or at the ceiling price. A monetary penalty has no effect on permit price or availability, sufficiently punishing non-compliers without subjecting all market participants to the after-effects of others' negligence. (IETA1)

Comment: Kern is concerned about potential excessive penalty amounts (violations accrue per allowance/per day). Kern suggests that there be limitations on daily penalties, while adding any costs that were saved by not complying. Kern is opposed to the 4:1 allowance penalty. Not only is this a large expense, but it shorts the market of credits. Kern suggests that a 1:1 ratio be used. (KERNOIL1)

Comment: ARB has structured the provisions such that operators that fail to surrender their compliance obligation in a timely manner are subject to a penalty requirement of four times the insufficient amount and an additional, separate penalty for "each day" of the violation. Imposing duplicative penalties for the same offense is unnecessarily stringent. In addition, requiring the violator to surrender "4 times the number of allowances" will potentially penalize others in the market as it will force the early retirement of instruments that could otherwise be available for use by others in the market. Chevron recommends ARB revise the enforcement provisions, so that late or insufficient surrender of instruments should be subject to a surrender of one allowance plus the payment of penalty in dollars equal to the price for the additional number of allowances. Chevron recommends that all other enforcement remedies would be contingent on non-compliance with the original allowance surrender penalty. (CHEVRON1)

> **Response:** See the responses to Comments J-15, J-20, J-23, and J-25. The additional surrender of allowances is not a penalty, but is necessary to ensure the environmental integrity of the cap-and-trade program as a deterrent to noncompliance. To prevent the reduction in supply of compliance instruments to other covered entities, we modified section 95857(d) to return allowances submitted to cover an untimely surrender to the auction account.

Offsets Use for Untimely Surrender

J-33. (multiple comments)
Comment: ARB should remove the limitation on the types of allowances that may be used to satisfy the 4:1 penalty shortfall; specifically, PacifiCorp believes that regulated entities should be allowed to use both allowances and offsets in this situation. Since the certification provisions for offsets ensure that they meet ARB's additionality requirements, there is no reason why the proposed regulation should include this limitation on the use of offsets. (PACIFICOR1)

Comment: Any approved compliance instrument should be eligible for untimely surrender obligation, not just California GHG allowances. Such a provision should be deleted as it is unnecessarily restrictive. Any approved allowance or offset credit that is eligible for use in the California cap-and-trade program overall should also be eligible for use to fulfill any surrender obligation. Otherwise, divergent treatment of compliance instruments available through ARB approved offset protocols or ARB approved external trading programs sends incorrect signals to investors that such compliance instruments are inferior and less valuable than California GHG emission allowances. Modify section 95857(b)(3) as follows:

(3) *A covered entity's compliance obligation for untimely surrender may only be fulfilled with ~~CA GHG allowances or allowances issued pursuant to~~* compliance instruments issued pursuant *to subarticle ~~12~~* 4." (LADWP1)

Response: We modified the regulation to allow up to one-fourth of the untimely surrender obligation to be met through the use of offsets, so long as it does not exceed the offset limit use contained in section 95854, for the applicable compliance period. We believe that the additional surrender of allowances serves as a strong deterrent to not meeting regulatory deadlines and ensures the environmental integrity of the cap-and-trade program.

Layering of Penalties with the MRR

J-34. Comment: Under section 96014(a) (p. A-180), there will be a separate violation for each compliance instrument that is not surrendered to meet a covered entity's surrender obligation. Additionally, under section 96014(b) (p. A-181), there would be a separate violation for each day after the compliance date that each required compliance instrument has not been surrendered. These provisions for per-ton per-day violations should be considered in light of the penalties that may be applied under the revised MRR—also on a per day, per ton basis—and the requirement in section 95857 for the imposition and recovery of the untimely surrender obligation: four times the excess emissions. Without modification, these overlapping penalty provisions will constitute a grossly excessive burden. It would be more appropriate to impose per-day penalties under the revised MRR without any per-ton multiplier. Per-day penalties would meet the legitimate objective of ensuring that reports and verification statements are provided promptly. Conversely, per-ton penalties should be imposed under the Cap and Trade Regulation without any per-day multiplier. Per-ton penalties would meet the legitimate objective of ensuring that covered entities surrender the correct amount of compliance instruments to meet their surrender obligation. Additionally, there should not be a violation under section 96014 if an entity incurs an untimely surrender obligation and that obligation is met in full within the 30-day period provided in section 95857(c)(4) (p. A-73). The "compliance date" that is specified in section 96014(b) should be the end of that 30-day period. The ARB recognized the issues with imposing per-day penalties in addition to penalties for each missing instrument in relation to the Renewable Electricity Standard ("RES") regulation. Similar concerns apply here and should be addressed during the "15-day" process. (SCPPA1, SCPPA5)

Response: We worked extensively with stakeholders to ensure that penalties are not "layered" between the MRR and the cap-and-trade regulation. A covered entity reports its emissions under the MRR. Those emissions are then verified, and the covered entity receives either a positive, qualified positive, or adverse emissions verification statement. In the event of either a positive or qualified positive verification statement, ARB accepts the emissions reported. The entity's compliance obligation is equal to one allowance for each ton emitted. If a covered entity receives an adverse verification statement, ARB uses default emission factors and calculates the covered entity's compliance obligation.

To the extent that a covered entity misreports emissions under the MRR, then amends the report (or get assigned an emissions number under the MRR) in time to surrender obligations under the cap-and-trade regulation, that entity faces penalties under only one rule: the MRR. If the error is discovered after the entity has already surrendered its original compliance obligation under the cap-and-trade regulation, section 95858 (added in response to stakeholder comments) gives the entity an additional six months to make up any additional surrender obligations related to the error. In this second situation, (assuming that the instruments are surrendered during the six-month period) the entity faces potential penalties under only one rule: the MRR. Independent of MRR compliance, once a surrender obligation has been established, an entity that fails to surrender compliance obligations under the cap-and-trade regulation faces potential penalties under only one rule for that failure: the cap-and-trade regulation.

To address the concern that per-ton per day violations may result in penalties that are too burdensome, we changed the basis for determining the number of violations. We modified section 96014 so that violations would be calculated on a per-ton basis after every 45-day period in which the covered entity fails to meet its surrender obligations. While we did not adopt the suggestion that the 30-day provision in section 95857(c)(4) be the "compliance date," we did add section 95857(b)(6) to give the covered entity time to access one auction or reserve sale before the untimely surrender is due. We believe that the process now provides adequate time for covered entities to meet their obligations. See also the responses to Comments J-15, J-20, J-23, and J-25.

J-35. (multiple comments)
Comment: For the staff report section on enforcement, we do not see it so clearly and are concerned about the potential exposure to draconian enforcement actions over potential inaccuracies in complying with a half-finished, overly complex and sometimes convoluted set of requirements. Moreover, we are concerned that the violation and penalty structure as detailed in section 95107 of the MRR could lead to a layering of penalties. In fact, we agree with the Western States Petroleum Association that "one piece of missing or incorrect data (out of potentially millions of pieces of data) could lead to potentially massive penalties. In other words, failure to measure, collect, record and preserve data could lead to a violation and penalty for "each ton, for each day" that the alleged failure occurred." (PLOTKIN)

Comment: We are concerned that the violation and penalty structure as detailed in Section 95107 of the MRR could lead to a layering of penalties such that one piece of missing or incorrect data (out of potentially millions of pieces of data) could lead to potentially massive penalties. In other words, failure to measure, collect, record and preserve data could lead to a violation and penalty for "each ton, for each day" that the alleged failure occurred. Further as noted in sub-sections (a), (b), (c) and (d) the same "failure" regardless of the reason or circumstance could be subject to penalties under the different sections potentially leading to tripling or quadrupling of penalties for the same alleged violation. As the mandatory reporting rule is tied to the proposed cap and trade rule, it is critical that the cap and trade rule also be addressed accordingly. We urge that the adopting resolution acknowledge that this multiplication of penalties, whether in the Cap and Trade Rule or in the Monitoring Recordkeeping and Reporting (MRR) Rule, is not the intent and that ARB is committed to addressing this issue in order to make the penalty structure fair and rational. (WSPA1)

Comment: The proposed regulation should not create potentially overlapping penalty provisions. The proposed regulation, in conjunction with the MRR, authorizes ARB to impose four separate penalty provisions for the same activity in parallel. First, the proposed regulation would impose a separate violation for each compliance instrument that is not surrendered to meet a covered entity's compliance obligation. Second, regulated entities may be subject to a separate violation for each day after the compliance date that a compliance instrument has not been surrendered. Third, the proposed amended MRR would apply penalties on a per-day, per-ton basis. Fourth, the proposed regulation would assess an excess emissions obligation of 4:1 for every allowance that should have been surrendered, but is not surrendered.

The overlapping penalty provisions under the proposed regulation would constitute a gratuitous enforcement action if more than one penalty were to be applied. We recommend imposing penalties only on a per-ton basis under the Cap-and-Trade Program, without any per-day multiplier. Per-ton penalties would meet the legitimate objective of ensuring that covered entities surrender the correct amount of compliance instruments to meet their surrender obligation. Furthermore, there should not be a violation if a regulated entity incurs an untimely excess emissions obligation and subsequently satisfies its excess emissions obligation within the 30-day period in the proposed regulation. (PACIFICOR1)

> **Response:** See the response to Comment J-20 (4:1 and per-ton) and J-33 (layering). The scenarios posited by the commenters could not occur, considering how the cap-and-trade regulation and the MRR interact.
>
> We disagree with the comment that the provisions in the cap-and-trade regulation on violations and penalties overlap. Each provision is designed to deal with a separate issue in setting penalties.

Allow More Time to Purchase Allowances for Excess Emissions

J-36. Comment: Covered entities should be given adequate time to purchase allowances at auction for excess emissions. The draft regulation indicates that the obligation to surrender allowances for excess emissions is immediately due, and the Executive Officer may pursue enforcement activities if a covered entity does not surrender sufficient allowances equal to this untimely surrender obligation by the end of the 30-day period. The LADWP recommends that ARB provide covered entities with the opportunity to purchase allowances at the next quarterly auction. This timeframe could be less than 30 days or up to 3 months, but it offers the covered entity a more reasonable opportunity to purchase allowances without going to the secondary market or allowance reserve. Additionally, LADWP recommends that this section be revised such that it is clear that the covered entity has a set period of time until the next quarterly auction to true up its compliance obligation for untimely surrender before the Executive Officer pursues enforcement activities. In other words, the Executive Officer shall not impose penalties pursuant to Subarticle 15 unless the covered entity has failed to secure adequate allowances by the time the next quarterly auction is completed and auctioned allowances are transferred into the covered entity's compliance account. (LADWP1)

> **Response:** We agree with the need to provide covered entities with an opportunity to purchase at an auction or Reserve sale before the excess emissions obligation is due. We added section 95857(b)(6) so that the excess emissions obligation will not be due until five days after the next auction or reserve sale for the which the entity may still register.

Ensure Strong Penalties

J-37. (multiple comments)
Comment: Direct responsibility for the impact of one's business processes on resources and the environment must be strongly enforced. (WHIPPLE)

Comment: Please stay strong to stop the companies that violate the standards. Fine them to get their attention. This is a critical issue for the long term future of our civilization. (FRERIKS)

Comment: I'd like to stress that our heaviest polluters need to pay for the pollution they generate, as opposed to being able to pollute for free. Only when penalized monetarily will they even think of changing. When they're not challenged, they will always keep the status quo and only adapt when it benefits them to do so economically. (NGUYEN)

Comment: Strong limits need to be set and no waivers allowed which will help businesses make long-term investments in strategies to reduce global warming emissions. Please enforce standards by imposing and collecting fines that are commensurate with the profits of polluters. These funds can then be used to accelerate the efforts to transition the state to a cleaner economy and lowering energy costs for Californians. (AMSDEN)

Comment: We are pleased to see that the proposed regulation contains several elements that I believe will make the program effective, including strong enforcement requiring a multiple of four allowances to be surrendered within 30 days for every allowance not surrendered on time plus monetary fines for further non-compliance. (LUDLOW, UCS1, WALTERS)

> **Response:** We intend to fully enforce the regulations.

Penalty Conflict/Dispute Resolution

J-38. (multiple comments)
Comment: The complexities of the proposed program will likely result in the need for regulatory interpretation and conflict resolution for differing opinions between CARB staff and regulated entities. Instances of unanticipated long-term deviations from regulatory requirements will likely occur because of breakdowns or other circumstances beyond the control of the facility. During these events, an opportunity to obtain "variances" should be available to avoid unnecessary or misguided enforcement action. The Sanitation Districts recommend that CARB establish both an independent body for dispute resolution, as well as a hearing board, similar to the SCAQMD Hearing Board, where variances from the cap and trade regulation can be obtained. Finally, independent market monitoring and at least annual internal program evaluation by CARB should be accomplished to look for and fix program weaknesses and to ensure reasonable market behavior. (LASD1)

Comment: It would be helpful to clarify any dispute resolution procedures, including accompanying time frames, with respect to surrender obligations. These types of provisions will enhance regulatory certainty for both covered entities and implementing agencies. (CCAP1)

Comment: CCEEB recommends that the ARB establish an independent administrative dispute resolution process that will provide a fair, efficient, and predictable process available to all regulated entities. This will reduce the money and time spent defending lawsuits and in informal negotiations. It will also increase the transparency of the appeal process as all interested stakeholders can weigh-in during the hearing. The proposed dispute resolution process could be modeled after existing air pollution hearing processes developed by the ARB for disputes that occur under local air district rules. (CCEEB1)

Comment: While NCPA does not dispute that the Executive Officer should have discretion to direct and monitor the Program, the Executive Officer’s conduct should be based on clearly defined and articulated guidelines made clear to all entities subject to the regulation, and these requirements must be clearly set forth in the final regulation. For example, in sections 95831(b) and 96011, the Executive Officer may suspend, revoke or otherwise restrict registration and accounts of various entities, which prohibits participation in the auction and could impact the ability to purchase and hold allowances. In sections 95912(e), if the Executive Officer makes a determination regarding certain bidder activities, the bidder is subject to penalties and prohibition from future auctions. Because participation in quarterly auctions are going to be key to meeting annual compliance commitments, it is imperative that any such actions be taken only with full notice and an opportunity to be heard. The proposed regulation should include specific provisions that address due process issues that arise in these provisions. (NCPA1)

Comment: We strongly recommend that the Board direct staff to develop regulations for the operation of an independent administrative dispute resolution board. The sole purpose of this entity would be to adjudicate those factual, legal and jurisdictional disputes that will inevitably arise in the implementation of the AB 32 program. (CCC, MAZOWITA)

Comment: There are innumerable situations under such a comprehensive regulatory program in which such factual, legal and jurisdiction disputes will arise. The absence of an expert administrative dispute resolution body will not avoid controversy. Controversies will arise. If there is no administrative mechanism for dispute resolution, then parties will simply direct such disputes to courts of law, likely resulting in significant unnecessary litigation, increased cost of compliance, excessive uncertainty and delay. (CCC, MAZOWITA)

Comment: The regulation should ensure that due process is applied in all enforcement cases under the cap and trade program. ARB should provide a mechanism by which respondent entities can review and respond to allegations before penalties are assessed. (WPTF)

Response: We disagree and do not believe a dispute resolution board is necessary. Any such process would add cost and complexity for both ARB and regulated parties. We believe that delays and uncertainty incumbent in a new, untried proceeding could disrupt the market features of the cap-and-trade regulation. Covered entities have sufficient time to obtain the allowances required for their compliance obligations. The process of obtaining and surrendering compliance instruments is not an industrial process subject to unexpected equipment breakdowns of the kind that form the basis for variance requests submitted to air districts. A variance process would be inappropriate in this regulation. The emissions at issue have already occurred and been reported to ARB; therefore, no “variance” is required. Instead of a formal variance process, the MRR includes a process by which a facility may petition for an interim data collection method under certain circumstances that would result in loss of data due to unforeseen reasons. The MRR also contains a dispute-resolution process for when a reporting entity and its verifier do not agree on the quality of the emissions data report. We believe that these two design features will ensure an efficient market process where timely data are critical to the functioning of a well-developed market program and that they will address the commenter’s concerns. Finally, we will be contracting for the services of an independent market monitor to help identify any issues in the implementation of the market program and to ensure market integrity.

ARB disagrees with the commenters’ premise that there is no fair, independent method of resolving disputes that may arise. As one commenter acknowledges, the existing recourse is to challenge a decision in court. That process is well established, transparent, and understood by regulated entities, the public, and ARB. Inventing a new, additional dispute resolution process, whether that would be through the creation of a hearing board or an administrative hearing, will not necessarily reduce the time or expense of resolving such disputes. In fact, and contrary to the claimed rationale of the commenter, ARB believes such additional process may actually increase the time and expense of resolving these matters, because after a hearing board process, either party could still ultimately take the dispute to court. Given the timelines in the cap-and-trade regulation, including an additional dispute resolution process would give rise to delay that could have broader market impacts.

Miscellaneous

J-39. Comment: To ensure fairness, the market rules and parameters must be known sufficiently in advance to provide all market participants information upon which to base their important business decisions. Missing elements such as reporting requirements and monitoring tools will make compliance with the program both difficult and confusing to participants. CalChamber urges CARB to develop a time schedule for the development of the compliance tools, policies and infrastructure necessary for entities to comply with this regulation. (CALCHAMBER1)

Response: This comment addresses implementation of the program rather than particular provisions of the regulation. However, we are developing a time schedule for the compliance tools and hope to have various tools available for covered entities by early 2012.

J-40. Comment: WSPA urges ARB to work with the regulated community to develop an enforcement guidance policy. That policy should address both the Cap and Trade and MRR enforcement provisions to avoid application of duplicative penalties within and among both of the regulations. It should also recognize an operator's earnest efforts to comply, yet allow enforcement and assessment of penalties on those operators that fail to comply. (WSPA1)

Response: We worked with stakeholders to refine the enforcement provisions in both the cap-and-trade regulation and the MRR so that there is no penalty "layering" between the regulations. See the response to Comment J-34.

J-41. Comment: The penalty provisions adopted from AB 32 remain confusing and inapplicable to the cap-and-trade context and should be further clarified. (SCE1)

Response: We clarified the penalty provisions in sections 96013 and 96014. See the responses to Comments J-14, J-15 and J-19.

K. LEGAL

This section includes comments and responses about legal issues surrounding the regulation, and refer but are not limited to sections 96020–96022. Major topics include offset protocols, the extent to which the regulation addresses AB 32 requirements, and the Commerce Clause.

Protocols

K-1. Comment: ARB's proposed cut-off in 2014 would make sense only if ARB provided a procedure to transition existing projects verified under early-action protocols (such as the CAR protocol as well as ACR and VCS) to an ARB protocol without significant additional cost and without changing the eligibility rules under which the forest project was started, since the financial values (and economic viability) of early action projects depends on the crediting period and eligibility rules under which the project was commenced.

ARB has not yet provided a procedure for such a transition, and without such a procedure, the value given to early action forest projects would be severely diminished since most forest projects do not generate significant carbon reductions until up to ten years into the project and would have relatively little carbon credit accumulated by 2014 despite significant financial investment. Moreover, such a policy would perversely disincentivize projects using hardwood species, which deliver comparatively more co-benefits due to the longer maturation of those carbon stocks. In short, any cut-off deadlines for early action must be linked to the availability of a procedure for transitioning existing early action projects to the ARB Forest Protocol. And, as discussed below, such transition rules cannot impose significant new costs or change eligibility criteria in a manner that would undermine the early action nature of the project as a practical matter. Any contrary rule would be inconsistent with AB 32 and has not been justified either under APA or CEQA. (FCC, BLUESOURCE)

> **Response:** We do not agree that limiting the start date or providing a 2014 date for an end to early action are inconsistent with AB 32. New section 95990(k) was added to clarify how early action offset projects transition to Compliance Offset Protocols. New section 95990(k)(2) clarifies that once an early action offset project transitions to a Compliance Offset Protocol it will begin an initial crediting period. The crediting period under the early action offset program does not count under the compliance offset program, so the early action offset project may transition to a Compliance Offset Protocol any time before February 28, 2015, but must list or register with an Early Action Offset Program by January 1, 2014 (section 95990(c)(3)). We removed any requirements that restrict the earliest date that early action offset projects must transition to Compliance Offset Protocols. It is necessary for offset projects beginning February 28, 2015, to transition to Compliance Offset Protocols to ensure consistency in the program and that all offset projects are following the rules of the regulation, including the rules in the Compliance Offset Protocols.

K-2. Comment: ARB needs to provide greater clarity on how project owners and offset project developers should obtain timely clarification on certain aspects of the protocol. (It is not clear whether qualified positive verification statements will allow verifiers to accept deviation from or slight changes to protocols as dictated under certain project specific circumstances). Currently, updates to quantification methodologies have to be made public through a public review and Board adoption process. There are likely to be numerous instances where project owners and developers require clarity on the interpretation of the guidance provided or wish to deviate from the protocol due to some unforeseen event. Waiting for public review and board approval may result in the project missing deadlines prescribed in the regulations. ARB needs to enable verifiers and/or registries to make decisions on deviations and variances within a short-time frame and to specify what constitutes a deviation or variance. (CIG)

> **Response:** Updating numerical or equation-related aspects of the protocols is considered part of the protocol's quantification methods. Changes to quantification methods can be updated through stakeholder input and Board action without having to go through the full APA (Administrative Procedure Act) process. ARB will develop guidance documents to aid in the use of the compliance offset protocols. As these methods are part of a regulation, any deviation from a documented ARB quantification method is not allowed. As ARB and approved registries get questions from offset project developers, these will become part of Q and A's posted on ARB's website.

K-3. Comment: The forestry protocol states in section 3.5 that conservation easements must "expressly acknowledge that ARB is a third party beneficiary of the conservation easement with the right to enforce all obligations under the easement." Again, this is a barrier for projects with a 2007-2010 commencement date, for which the relevant easement would already be in place. It seems to us that a Federal conservation easement that, for example, protects project lands in perpetuity and subordinates all timber harvest rights under the easement, which is itself legally enforceable under state and Federal law, ought to provide a sufficient basis for enforcement. (CIG)

> **Response:** Under the Forest Offset Protocol, only avoided conversion projects require a Qualified Conservation Easement to be eligible; other project types may reduce their risk rating and required forest buffer account contributions with a Qualified Conservation Easement but would still be eligible if the easement was not "Qualified". Offset Project Developers or Authorized Project Designees may be able to modify an existing easement to include ARB as a third-party beneficiary so that it will meet the definition of a Qualified Conservation Easement. Requiring ARB to be a third-party beneficiary to a conservation easement ensures that the provisions of the easement are enforceable and that ARB would be a party to any potential future modifications to the easement. The definition of a qualified conservation easement under v3.2 of the CAR protocol is similar to that of ARB, but instead requires identifying the terms and conditions of

the Project Implementation Agreement in the easement. Thus the commenter would need to modify the easement to qualify as an early action project under CAR v3.2 or under ARB's Forest Offset Protocol.

K-4. Comment: The regulation is silent on what happens after 2020. There must be a mechanism to address violations for facilities that do not surrender enough compliance instruments to cover their emissions in the third compliance period. (CAPCOA1, CAPCOA2)

Response: The enforcement provisions of the regulation will remain in full force and effect after 2020. If a covered entity does not surrender sufficient compliance instruments in the third compliance period, the additional surrender obligation would also remain. Additional reductions will likely be necessary after 2020 to meet long term climate change goals. At this time it would be premature to speculate how those additional reductions would be achieved.

K-5. Comment: ARB's decision to limit the start date for early action forestry projects, as well as its decision to cut off crediting in 2014, is inconsistent with AB 32, is unsupported by the record or environmental review, and therefore would be illegal if adopted as written. (FCC, BLUESOURCE)

Response: We do not agree that limiting the start date or providing a 2014 date for an end to early action are inconsistent with AB 32. The start date is needed to ensure that projects are additional and were not implemented as part of business as usual prior to the drafting of AB 32. The cut-off date is to ensure that all offset projects transition to the Board-approved compliance protocols in a timely manner. This eligibility period allows us to provide some offset credit for additional projects that were implemented early under less stringent protocols and time for those early action projects to transition to the compliance program.

K-6. Comment: The limitation in section 95990(b)(4) restricting forest projects to those developed under the Climate Action Reserve Forest Protocol is likewise improperly restrictive and anti-competitive. Although significant investment has been directed at CAR projects, the CAR forestry protocol was only made available relatively recently, and many worthy projects were initiated under other protocols, such as administered by ACR and VCS. The ISOR appropriately recognizes the "rigor" of the CAR program and notes that the CAR program began in 2005, ISOR at III-21, but gives no justification for failing to consider other rigorous programs under which forest offset projects have already been approved and issued credits.

Moreover, discriminating in favor of CAR, a private California non-profit organization, and disadvantaging other registries and forest offset programs raises a host of equal protection and constitutional commerce clause concerns, such that the restriction to CAR- only projects is arguably illegal. In a scant reference, ARB states that it is "aware" that other voluntary offset programs have protocols, but fails to provide any discussion of its rejection of these programs or other existing protocols. Although section 95990(c) appears to authorize other "third-party offset programs" to administer early action credits, it does not appear that credits issued under protocols other than the CAR Forest Protocol will be recognized, thus presumably disqualifying forest projects that would be otherwise legitimate but for the fact that the project developer sought registration under a competing protocol. Nor can ARB impose eligibility criteria that would have the effect of disqualifying early action projects started under other programs unless ARB can demonstrate that such criteria are mandated by AB 32. Because ARB has not shown that forest projects registered under ACR, VCS, or other programs are not legitimate early action projects, it must provide a mechanism for crediting those projects. (FCC, BLUESOURCE)

> **Response:** ARB will continue to consider and evaluate additional protocols for compliance and early action. Three of the four protocols included for early action had already been reviewed and endorsed by the Board for voluntary use after an ARB public process. ARB staff participated on the work group for the fourth protocol. By not including other protocols for early action at this time, we are not precluding them from future consideration. Staff anticipates returning to the Board with additional protocols and will continue to evaluate those protocols currently included in the regulation.

General and Miscellaneous Legal

K-7. Comment: The California Administrative Procedure Act requires each rulemaking agency to "consider all relevant matter presented to it during a comment period before adopting any regulation." The undersigned companies have substantial doubt whether ARB has left itself adequate time to consider each of these comments and to revise the rule accordingly. It is our understanding that a Board vote is scheduled for December 16, with the close of public comment on December 15. That timing leaves little room for the agency's duty under the Administrative Procedure Act to consider each relevant, timely public comment. However, it is our understanding that ARB will undertake appropriate revisions to the proposed rules, and we look forward to working with ARB to work through these important issues and implement appropriate revisions to the market rules and Forest Protocol where necessitated by law and good policy. (FCC, BLUESOURCE)

> **Response:** The California Administrative Procedure Act (APA) requires that all relevant matter be considered, however, it does not require that all relevant matter be considered before a Board hearing. Staff may consider the comments in formulating any 15-day changes to the regulation, which is what staff has done in this instance. The responses to comments are contained in this document, as required by the APA, and are available for public review.

K-8. Comment: BPA appreciates that ARB has afforded BPA Asset Controlling Supplier status through the greenhouse gas reporting regulations (section 95102 (a)(15), 95111(b)(3), 95111(f), and in ARB's Cap and Trade regulations section 95802(a)(8)). However, BPA disagrees with ARB's suggestions in its greenhouse gas reporting rules and cap and trade rules that it has "authority" to regulate BPA and that BPA is "required" to comply (see section 95101(d)(5), 95102(a)(102), 95802(a)(59)). BPA wishes to make clear that BPA is participating in California's GHG reporting program and Cap and Trade program purely on a voluntary basis and BPA is not conceding that California has any jurisdiction over BPA. Sovereign immunity may prevent BPA (and similarly WAPA) from being subject to these regulations. Despite ARB's position that the Clean Air Act waives sovereign immunity, it is questionable whether that waiver would cover BPA because it is purely a marketer that is not engaged in an activity that discharges pollutants. Further, although BPA intends to voluntarily comply with these regulations, BPA is concerned that mandatory regulations could interfere with its existing contracts and conflict with the marketing scheme established by Congress in BPA's governing statutes. Because BPA is willing to voluntarily comply, it is not necessary for ARB to include these jurisdictional assertions in its rules. Doing so could unnecessarily raise complicated legal issues that are unnecessary to full and timely implementation of the greenhouse gases reporting rules and/or the cap & trade program. Accordingly, BPA urges ARB to modify sections 95101(d)(4) and (5), 95102(a)(102), and section 95802(a)(59) (same definition of "Electricity importers" as the definition used in section 95102(a)(102)) in one of two ways, either by simply deleting the unnecessary language entirely, or by modifying it. The following illustrate both options for each of the three sections:

Delete option for section 95802:

(a) Definitions. For the purposes of this article, the following definitions shall apply:

(59) "Electricity importers" are marketers and retail providers that hold title to imported electricity. For electricity delivered between balancing authority areas, the entity that holds title to delivered electricity is identified on the NERC E-tag as the purchasing-selling entity (PSE) on the tag's physical path, with the point of receipt located outside the state of California, and the point of delivery located inside the state of California. ~~Federal and s~~State agencies are subject to the regulatory authority of ARB under this article and include~~ Western Area Power Administration (WAPA), Bonneville Power Administration (BPA), and~~ California Department of Water and Power (DWR). When PSEs are not subject to the regulatory authority of ARB, including tribal nations, the electricity importer is the immediate downstream purchaser or recipient that is subject to the regulatory authority of ARB.

Modification option for section 95802:

(a) Definitions. For the purposes of this article, the following definitions shall apply:

(59) "Electricity importers" are marketers and retail providers that hold title to imported electricity. For electricity delivered between balancing authority areas, the entity that holds title to delivered electricity is identified on the NERC E-tag as the purchasing- selling entity (PSE) on the tag's physical path, with the point of receipt

located outside the state of California, and the point of delivery located inside the state of California. ~~Federal and s~~State agencies are subject to the regulatory authority of ARB under this article and include ~~Western Area Power Administration (WAPA), Bonneville Power Administration (BPA), and~~ California Department of Water and Power (DWR). Federal agencies, including Western Area Power Administration (WAPA) and Bonneville Power Administration (BPA), are not subject to these regulations so long as they voluntarily participate under these regulations. When PSEs are not subject to the regulatory authority of ARB, including tribal nations, the electricity importer is the immediate downstream purchaser or recipient that is subject to the regulatory authority of ARB. (BONNEVILLEPWR)

Response: Section 118 of the Clean Air Act constitutes a waiver of sovereign immunity for federal agencies such as BPA. Additionally, this document only responds to comments regarding the cap-and-trade regulation (which includes section 95802) but does not include the other specific sections with which BPA takes issue which are included in the MRR . Although the definition of "electricity importer" has changed through the course of two 15-day notices, BPA, DWR and WAPA remain specifically named as electricity importers to California and subject to the cap-and-trade regulation. Title 42 U.S.C. section 7418 (Section 118) specifically states:

(a) General Compliance

Each department, agency, and instrumentality of the executive, legislative and judicial branches of the Federal Government

(1) Having jurisdiction over any property or facility, or

(2) engaged in any activity resulting, or which may result, in the discharge of air pollutants, and each officer, agent, or employee thereof, shall be subject to, and comply with, all Federal, State, interstate, and local requirements, administrative authority, and process and sanctions respecting the control and abatement of air pollution in the same manner, and to the same extent as any nongovernmental entity. The preceding sentence shall apply

(A) to any requirement whether substantive or procedural (including any recordkeeping or reporting requirement, any requirement respecting permits and any other requirement whatsoever),

(B) to any requirement to pay a fee or charge imposed by any State or local agency to defray the costs of its air pollution regulatory program,

(C) to the exercise of any Federal, State, or local administrative authority, and

(D) to any process and sanction, whether enforced in Federal, State, or local courts, or in any other manner. This subsection shall apply notwithstanding any immunity of such agencies, officers, agents, or

> employees under any law or rule of law. No officer, agent, or employee of the United States shall be personally liable for any civil penalty for which he is not otherwise liable.

Section 118 is clear. Environmental laws of California apply to BPA "notwithstanding any immunity of such agencies, officers, agents, or employees under any law or rule of law." While ARB appreciates BPA's voluntary participation in the ARB programs, the language suggested by BPA is not necessary and appropriate because (1) sovereign immunity has been waived by section 118 of the CAA, and (2) the language is unclear because "voluntary participation" is a vague term that leaves unresolved whether the enforcement provisions of the regulation would apply to BPA.

K-9. Comment: ARB's method of including "imported electricity" as a greenhouse gas emissions source was not introduced in legislation, but was developed by ARB in order to implement AB 32. DWR's only activity triggering a surrender obligation under the regulations is based on the "first deliverer" method of identifying deliveries of imported electricity. DWR does not object to this methodology, but points out that as applied to DWR it appears to exceed ARB's authority. (DWR)

Response: ARB does not believe that including DWR in the cap-and-trade regulation exceeds ARB's authority to regulate greenhouse gas emissions. DWR is being treated in the same manner and principle as every other regulated entity subject to the cap-and-trade program. Simply because DWR is another state agency does not automatically make it exempt from the regulation. See the response to Comment K-8.

Comment Period

K-10. Comment: CSCME objects to the prejudicial manner in which CARB both established the comment period for the proposed regulation and scheduled the concomitant CARB meeting for its adoption. CARB stated that comments will be accepted through December 15 at noon, and that the public hearing to consider adoption of the proposed regulation will begin less than 24 hours later, at 9:00 a.m. on December 16. It is well-settled that "one purpose of the Administrative Procedure Act is to ensure that those persons or entities whom a regulation will affect have a voice in its creation." The schedule CARB set forth virtually ensures that neither CARB members nor staff will have the opportunity to review all submitted comments prior to the hearing. Based upon the volume and complexity of the proposed regulation and supporting documentation, CARB's approach violates fundamental due process principles and is inconsistent with the California Administrative Procedure Act (APA). In State Water Resources Control Board v. Office of Administrative Law, a California Court of Appeal found that 15 days, although a short period of time to consider comments from interested parties, was not so short as to render the task impossible. In contrast, it is impossible for CARB to give adequate consideration in one afternoon to comments on a proposed regulation that will affect virtually every sector of the California economy. (CSCME2)

> **Response:** The initial public comment period for the proposed regulation was determined based on Government Code section 11346.4(a), which requires that, at least 45 days prior to the hearing "on the adoption, amendment, or repeal of a regulation" notice be posted in accordance with the requirements of that section. At the December 16, 2010, hearing the Board did not take final action to adopt the proposed regulation, but instead approved Resolution 10-42, which directed the Board's Executive Officer to take a number of actions. Among other things, Resolution 10-42 directed the Executive Officer to hold one or more workshops on proposed modifications to the regulation to provide an additional opportunity for public input, to make the modified regulatory language available for one or more formal public comment periods, to consider written comments that may be submitted, and to make such modifications as may be appropriate in light of the comments received. At the end of this process, the Executive Officer was further directed to either take final action to adopt the proposed regulation with the additional modifications, or return the proposed amendments to the Board for further consideration before taking final action, if he determines that this is warranted.
>
> In response to the Board's direction, the Executive Officer took the actions specified in Resolution 10-42 and then determined that it was appropriate to return the proposed regulation to the Board for further consideration. This occurred at a public hearing held on October 20, 2011, at which the Board took final action to adopt the proposed regulation, with the modifications made since the regulation was first considered by the Board at its December 16, 2010, public hearing.
>
> From the above description it can be seen that the December 16, 2010 public hearing was simply an interim step in a long administrative process culminating in final adoption of the regulation by the Board on October 20, 2011. During this long process there was adequate time for all comments to be thoroughly considered by both ARB staff and the Board. We believe that this process is a fair one that complies with all applicable laws, including the Administrative Procedure Act and constitutional due process principles.

K-11. Comment: Constellation Energy suggests that additional time be allocated to consider and address public comment. Given the far-reaching impact of the rule, it is important that the contributions of all stakeholders be fully considered. The comment period ends at noon on December 15, and CARB will vote on the proposed regulations during the December 16–17 meeting. Given the potential for thousands of comments, CARB will be hard put to review, let alone seriously consider comments in such a timeframe. On a similar note, Constellation Energy is skeptical that issues related to IPPs can be resolved within a 1-2 day period. (CONSTELLATIONENERGY)

Response: This comment is addressed in the response to Comment K-10.

K-12. Comment: We are concerned that CARB has begun a pattern of passing regulations before they are completed and using the 15 day update process to attempt to fill in holes. We believe this is illegal and wrong and the practice flies in the face of requirements that the record be complete prior to voting on a measure if for no other reason than it precludes regulated parties from doing a complete analysis and filing fully informed comments to say nothing of the practice making it impossible to do a complete cost effectiveness analysis required by both the Administrative Procedure Act as well as AB 32. The full range of details required to understand and implement the Cap and Trade program have not yet been fully sorted and accounted for. Many of the tools, provisions, and methods still being developed by CARB will provide crucial information for business operations in California. There is no confidence that the information will be available or even determined prior to the last quarter of 2011 or even before the start of the market in 2012.

CIPA also agrees with the AB 32 Implementation Group that CARB has no current authority, under AB 32 or otherwise, to raise revenue for purposes unrelated to administration of the AB 32 program. The statement of reasons does not demonstrate that an auction to raise revenue is necessary for, or limited to, administration of the program, which is the only authority bestowed by AB 32. We also agree with the AB 32 Implementation Group that an auction and its proceeds are not only unauthorized by AB 32, but equate to a tax that will require 2/3 vote of the legislature. (PLOTKIN)

Response: ARB has complied with all statutes and regulations in adopting the cap and trade regulations, including the requirements of the Administrative Procedure Act (Government Code sections 11340 et seq.) See also the response to Comment K-10, which explains that the Board did not take final action to adopt the regulation at the December 2010 public hearing. In addition, after reviewing the comments received, ARB has changed the first year of the compliance obligation to 2013. This change should help address the commenter's concern that insufficient information will be available to businesses before the start of the program. .

ARB respectfully disagrees with the assertion that the cap-and-trade program is a tax and is unauthorized. The cap-and-trade program itself is a market based program specifically authorized in Health and Safety Code section 38562(c).

The way a market-based program incentivizes GHG reductions is by placing a cost on carbon. By providing allowances for free at the beginning of the program, we are allowing for a measured start to get covered entities used to the program and to carefully start to include carbon price in their operations and products. The auction mechanism is used to put a price on carbon for the allowances that are not directly provided for industry assistance. As the program matures, there will be less industry assistance through direct allocation and entities will have to purchase the right to emit GHG's. The auction revenues are a product of the program design to incent GHG reductions. All revenue collected through auction will be appropriated at the discretion of the Legislature, not ARB. This revenue is not collected by ARB to appropriate as it desires.

K-13. (multiple comments)
Comment: The board should not vote on this proposal tomorrow as communities have not had sufficient notification. (MASCARENHAS)

Comment: Valero strongly urges ARB to complete the regulatory development process prior to adoption, so that the totality of the impacts can be meaningfully reviewed by the impacted parties. (VALERO)

Response: ARB has complied with all of the required notification processes and procedures of the Administrative Procedure Act. See also the responses to Comments K-10, and K-12, which explain that the Board did not take final action to adopt the regulation at the December 2010 public hearing.

Leakage

K-14. Comment: CARB unlawfully delegates its duty to minimize the leakage associated with indirect emissions to another state agency. CARB's delegation of the responsibility for regulating indirect emissions costs in leakage-exposed sectors to the California Public Utilities Commission (PUC) is unlawful because CARB has essentially abdicated its responsibility under AB 32 to minimize leakage in adopting regulations to reduce GHG emissions. AB 32 directs CARB, not PUC, to "adopt greenhouse gas emission limits and emission reduction measures by regulation to achieve the maximum technologically feasible and cost-effective reductions in greenhouse gas emissions." AB 32 further provides that in adopting those regulations, CARB must "to the extent feasible minimize leakage" and consider many other factors. In contravention of that command, CARB has delegated its responsibility under AB 32 to minimize leakage to PUC, and it has done so without providing PUC with any direction as to how to achieve AB 32's command. (CSCME2)

Response: ARB disagrees with the commenter. ARB's authority to implement the cap-and-trade program derives from AB 32, and, to the extent possible, ARB has examined leakage possibilities. However, ARB does not regulate several industries that are subject to the cap-and-trade regulation and does not have authority to impose additional obligations on those industries.

K-15. Comment: AB 32 directs CARB to design all GHG emissions-reduction measures, including market-based compliance mechanisms, in a manner that "minimizes leakage" to the extent feasible. CARB found that to minimize leakage, in-state and imported products need to be subject to the same standards. Finally, the California Supreme Court has held that a statute mandating an agency to take action "to the extent feasible" confers no discretion on that agency to ignore feasible actions that will aid the statute's stated purpose. (CSCME2)

Response: ARB has not ignored any feasible alternatives to the cap-and-trade regulation. ARB has examined all feasible alternatives to the cap-and-trade program, both from a regulatory and environmental perspective and has found that the cap-and-trade program is the best option to meet the AB 32 goals and is the least burdensome alternative. To further explain, as part of the development of the cap-and-trade program, we performed a careful leakage analysis and identified all industries that may be susceptible to emissions leakage. All industries that were identified as at risk for leakage will receive free allowances in the first compliance period. The mechanism for allocating allowances was designed to minimize the incentive to relocate production out of state. In this way cap and trade will achieve cost effective emissions reductions while fully minimizing leakage to the extent feasible. A complete description of this allocation approach is included Appendix K of the Staff Report.

Confidentiality

K-16. Comment: The Utilities are concerned there could be a conflict between section 95912 and various existing laws affecting POUs, such as the Public Records Act. Modify section 95912 as follows:

(d) Protection of Confidential Information.

(1) An entity approved for auction participation shall not publicly release confidential information related to its auction participation<u>, except as otherwise required by law</u>, including: (MID1)

Response: ARB significantly rewrote section 95912 including the subsection referenced. The section referenced has been changed to reflect the spirit of this comment, if not precisely the proposed change.

K-17. Comment: ARB should clarify the confidentiality provisions to ensure that information concerning allowance holding accounts and Cap-and-Trade transactions remain confidential. The proposed regulation provides that emissions information is public information and is not confidential. However, it is unclear whether information submitted under the MRR and information concerning the amount of allowances contained in a regulated entity's Holding Account could be made publicly available by ARB. ARB should specify that information related to allowances that have not been retired or retired ahead of the compliance deadline are not emissions information, and therefore will indeed be protected from public disclosure. (PRAXAIR, PACIFCOR1)

Response: ARB is continuing to evaluate what information submitted under the MRR would be made public along with whether individual holding account information would be public. The California Public Records Act specifies that all air pollution emission data are public records (see Government Code section 6254.9), and the regulation is consistent with this statutory provision. For information that is not emissions data, ARB anticipates additional consultation with the public to determine what information is entitled to confidentiality protection under California law. This is a complex and unresolved issue, and at this time it is not appropriate to further specify in the regulation the categories of non-emissions information that should either kept confidential or made public. Instead, ARB will follow its existing confidentiality regulations in making decisions on the disclosure of information (see title 17, California Code of Regulations, sections 91000 to 91022).

K-18. Comment: Fully disclose firm-level information used to administratively allocate allowances to regulated entities. Toward these transparency goals, EDF recommends that reports of emissions and trading activities be made publicly available. (EDF1)

Response: Disclosing too much information could result in a variety of market ills, including collusion, price fixing, bid fixing and other possible market manipulations. ARB intends to evaluate the information it collects and publicly release as much as possible, without creating a situation that could lead to market manipulation and collusion. As stated in the response to Comment K-17, ARB anticipates additional consultation with the public to determine what information is entitled to confidentiality protection under California law, and at this time it is not appropriate to further specify in the regulation the categories of non-emissions information that should either kept confidential or made public. Instead, ARB will follow its existing confidentiality regulations in making decisions on the disclosure of information (see title 17, California Code of Regulations, sections 91000 to 91022).

Compliance Instruments and Property Rights

K-19. Comment: Compliance instruments must be surrendered for the annual and triennial compliance obligations. There is apparent no enforcement by CARB until the final year of the three year compliance period. This could give rise to statute of limitations problems if timely verification of emissions and issuance of final determinations is not conducted in a timely fashion. (CAPCOA1, CAPCOA2)

Response: The regulation requires one-third of the estimated number of compliance instruments be surrendered in each of the first two years of the compliance period. Failure to surrender compliance obligations at any of these interim dates would subject a covered entity to an additional surrender obligation and potential penalties well before the end of the compliance period and the final surrender obligation.

K-20. Comment: The Utilities believe that the statement regarding a compliance instrument not being a property right should be limited for the purposes of this regulation only. Modify section 95820 as follows:
(b) Each compliance instrument issued by the Executive Officer represents a limited authorization to emit up to one metric ton in CO_2e of any greenhouse gas specified in section 95810, subject to all applicable limitations specified in this article. No provision of this article may be construed to limit the authority of the Executive Officer to terminate

or limit such authorization to emit. *<u>For the purposes of this regulation only, a</u> compliance instrument issued by the Executive Officer does not constitute property or a property right*. (MID1)

> **Response:** The proposed modification is not appropriate because it is unclear why it is necessary, and the legal effect of such a statement is also unclear. The statement seems to imply that compliance instruments can be both property and not be property, depending on the whether the instrument is either "for the purposes of the regulation" or for some other "purpose" which is not identified. It is very unclear how one would make such a distinction or what the legal or practical impact of such a distinction would be. ARB is not prepared to create such confusion and lack of clarity by including this language in the regulation.

K-21. Comment: There should be criteria on cause to terminate or limit authorization to emit or the sentence should be deleted. Modify section 95820 (c) as follows:

(c) Each compliance instrument issued by the Executive Officer represents a limited authorization to emit up to one metric ton in CO_2e of any greenhouse gas specified in section 95810, subject to all applicable limitations specified in this article. ~~No provision of this article may be construed to limit the authority of the Executive Officer to terminate or limit such authorization to emit~~. A compliance instrument issued by the Executive Officer does not constitute property or a property right. (CCEEB1)

> **Response:** ARB did not implement this suggestion. The Executive Officer needs broad authority to limit or terminate the allowances to ensure that, in the event of any violations, fraud, or other malfeasance in the conduct of the allowance market, it can be immediately addressed.

K-22. Comment: In creating a new program, CARB must also create surrender instruments to be used in the Program. Sections 95820 sets forth the general description of the "California Greenhouse Gas Emissions Allowances" and "offset credits." Section 95820(c) goes on to describe the compliance instrument, and notes that "[a] compliance instrument issued by the Executive Officer does not constitute property or a property right." The rationale for this limitation is based on the premise that "property rights cannot attach to the compliance instruments because, in the event of federal preemption in the cap and trade market or other conditions, California must have the ability to revoke the compliance instruments without creating a loss to the people of California." (ISOR, p. IX-18) NCPA recommends that the proposed regulation clarify that an allowance – whether it is a California Greenhouse Gas Emission Allowance or offset credit – does not constitute a compliance instrument until such time as it has been surrendered to CARB pursuant to the provisions of section 95856. (NCPA1)

> **Response:** All allowances or offset credits issued by ARB are compliance instruments upon their issuance. It is not clear what the purpose of issuing an

allowance would be if it were not also a compliance instrument for purposes of the regulation.

Exemption

K-23. Comment: The Railroads understand that, for purposes of diesel fuel, the MRR and Cap-and-Trade Rule are modeled on the reporting requirements of the Board of Equalization ("BOE"). While this approach may have been logical from the standpoint of streamlining existing reporting practices, ARB's decision to rely on the existing BOE reporting forms for defining the first point of supply unwisely places differing compliance burdens on the major transportation companies depending on the method through which they receive fuel from their suppliers, and thus would inhibit the competitiveness of some companies as compared to others within the same market. The fuel producers and fuel importers are the first supplier of fuel for both bulk and non-bulk transfers. Therefore, the fuel producers and fuel importers are the best source of information for purposes of reporting and compliance with AB 32, and it is illogical and overly-complicated to have different points of compliance based strictly on whether the fuels are transferred via the bulk or non-bulk system. Whereas non-bulk transfers will generally be reported by, and the compliance obligation will rest with, upstream fuel producers and fuel importers, the reporting and compliance obligation for bulk transfers is pushed downstream to multiple and various fueling facilities that might qualify as "terminals" under the Rule. As currently drafted, the Railroads could be determined to be "suppliers" of diesel fuel, and therefore "covered entities," under the proposed Cap-and-Trade Rule. This would mean that the Railroads would be required to acquire compliance instruments in order to supply diesel fuel to locomotives in California. By limiting the number of compliance instruments available to all covered entities in a given year, the Cap-and-Trade Rule would impose a *de facto* regulation on the Railroad's ability to supply diesel fuel to locomotives in California, notwithstanding the preemptive effect of the federal Interstate Commerce Commission Termination Act of 1995 ("ICCTA"). [The ICCTA's preemption of state and local regulations that impose an unreasonable burden on the railroad industry has been upheld in multiple court decisions. *See City of Auburn v United States Government* (154 F.3d I 025, 1029-31 (9th Cir. 1998) ("Congress intended to preempt a wide range of state and local regulation of rail activity"); *Association of American Railroads v South Coast Air Quality Management District* (9th Cir. 2010) 622 F.3d 1094 ("[the] ICCTA preempts those [local and state] rules unless they are rules of general applicability that do not unreasonably burden railroad activity").] The Railroads and Air Resources Board have long recognized this federal preemption of state and local authority to regulate railroads, and should continue to do so when implementing the MRR and Cap-and-Trade Rule.
(CRI)

Response: The coverage of the program is intended to provide a level playing field for all energy sources starting in the second compliance period. Fuel used for transportation is covered at the terminal rack as the regulated party with sufficient information about the amounts of fuel consumed in

California, is administratively manageable in terms of the amount of regulated parties, and is consistent with existing reports already submitted to a State agency as indicated by the commenter. Fuel producers do not always know whether the fuel they produce is consumed in California or out of state. We expect that the a carbon price will be reflected in fuel purchased by all end users and therefore we do not agree there is a competitiveness concern for end users whether they have a direct compliance obligation in the program or if they purchase fuels from entities that pass the costs through. We disagree that the program imposes a de facto regulation on the supply of diesel for railroads. The program has no limitation on the energy use or emissions of any single entity. Entities report the emissions for which they are responsible and are required to submit compliance instruments, allowances and offsets, at the end of a specified period of time. Entities are afforded the flexibility of a partial compliance annually and a full compliance every 3 years. Given this flexibility and the consistency with current reporting requirements to a State agency as noted by the commenter, the regulation is not unreasonably burdensome to railroads.

Nevertheless, ARB is committed to continuing to work with the railroads on addressing reporting concerns.

K-24. Comment: The regulation should expressly exclude DWR. DWR suggests the following addition and deletion:

Section 95811(h): <u>This article does not apply to the California Department of Water Resources.</u>

Section 95802(a)(59), "Electricity importers" are marketers and retail providers that hold title to imported electricity. For electricity delivered between balancing authority areas, the entity that holds title to delivered electricity is identified on the NERC E-tag as the purchasing-selling entity (PSE) on the tag's physical path, with the point of receipt located outside the state of California, and the point of delivery located inside the state of California. Federal ~~and state~~ agencies are subject to the regulatory authority of ARB under this article, and include Western Area Power Administration (WAPA) <u>and</u> Bonneville Power Administration (BPA) ~~and California Department of Water Resources (DWR)~~. When PSEs are not subject to the regulation authority of ARB, including tribal nations <u>and state agencies</u>, the electricity importer is the immediate downstream purchaser or recipient<u>, if any</u>, which is subject to the regulatory authority of ARB. (DWR)

Response: It is not appropriate to exclude DWR from regulation, because it is ARB's intent to include all emissions that are a result of electricity imported and delivered to the California grid. This includes the electricity DWR imports to run their operations.

Does Not Meet AB 32 Requirements

K-25. Comment: ARB should not adopt the cap and trade rule until a pending legal challenge to the scoping plan is concluded. On June 10, 2009, Petitioners Association of Irritated Residents, et al, represented by CRPE and Communities for a Better Environment (CBE), filed a Complaint for Declaratory and Injunctive Relief and Petition for a Writ of Mandate directing ARB to revise its Climate Change Scoping Plan to comply with Assembly Bill 32 (AB 32) and CEQA. Petitioners filed their First Amended Complaint and Petition (FAC).On February 19, 2010, Petitioners challenged the Scoping Plan because it inadequately sets up the overarching regulatory framework for AB 32's implementation. Further, the range of measures that the Scoping Plan has established dictates the parameters of the future options available to meet AB 32's goals. Petitioners raised a number of deficiencies in the Plan, and specifically raised four claims regarding ARB's inclusion of a cap and trade program: (1) ARB's failure to assess maximum technological feasibility and to develop a cost-effectiveness criteria with which to compare reduction measures to market mechanisms (FAC, First Cause of Action), (2) ARB's failure to analyze whether a cap and trade program could effectively facilitate the achievement of maximum feasible and cost-effective reductions of greenhouse gas emissions by 2020 (FAC, Second Cause of Action), (3) ARB's failure to consider the performance of cap and trade programs in other states, localities, and nations, including the northeastern states of the United States, Canada, and the European Union (FAC, Fourth Cause of Action), and (4) ARB's failure to adequately analyze alternatives to regional cap and trade (FAC, Eighth Cause of Action). Because the Scoping Plan lacks the fundamental analysis required, not only will AB 32 fail, but each subsequent regulatory program that flows from this Plan, such as the cap and trade rule, will share these fundamental flaws. Thus, the Board should not adopt the cap and trade rule before the Court rules on Petitioners' claims, for which the hearing is scheduled for December 20, 2010. (CRPE1)

> **Response:** The commenter's request for delay has already been denied by the Superior Court in their "Scoping Plan lawsuit." The Superior Court's order denying the commenter's request expressly contemplates the Board "resolving to adopt the Proposed Cap and Trade Rule" at its December meeting. Consistent with its representations to the Superior Court, ARB did not take final action to adopt the proposed cap-and-trade regulation at the December 16, 2010 hearing. Rather, the Board authorized the finalization of the regulation and authorized ARB staff to continue to work on the regulation. ARB also disagrees that commenter's legal claims have merit. As to claims (1), (2) and (3) described in the comment, the Superior Court ruled in ARB's favor, denying those claims. As to claim (4), ARB has appealed the Superior Court's ruling against it, and ARB has obtained a stay of the Superior Court's injunction from the Court of Appeal, thereby allowing ARB to proceed with this cap-and-trade rulemaking. In addition, although not required to, ARB staff supplemented its analysis of alternatives in the AB 32 Scoping Plan Functional Equivalent Document (FED) and, on August 24, 2011, the Board approved the Supplement to the AB 32 Scoping Plan FED and re-approved the Scoping Plan (see

www.arb.ca.gov/cc/scopingplan/document/appendices_volume3.pdf and www.arb.ca.gov/cc/scopingplan/document/final_supplement_to_sp_fed.pdf).

K-26. Comment: The offsets provisions directly violate AB 32's requirement that ARB "direct public and private investment toward the most disadvantaged communities in California." Offsets from out-of-state plainly violate this mandate. Linking California's trading program to the Western Climate Initiative could also contravene AB 32's requirement that greenhouse gas emission reductions achieved are enforceable by ARB. ARB has no authority to enforce the obligations of out of state entities. (CRPE1)

Response: The requirements in AB 32 section 38565 state, "to the extent feasible, direct public and private investment toward the most disadvantaged communities in California." This provision is extended to all AB 32 rules, regulations, programs, mechanisms, and incentives. AB 32 contains many objectives for the regulation that are adopted under its authority. ARB must balance these many objectives when designing regulations. The offsets program is a very small portion of the overall strategy to reduce GHG emissions in California. ARB is currently developing recommendations on the use of auction revenue that will examine potential ways to direct investment toward the most disadvantaged communities in California. The protocols currently adopted are applicable in California and the United States. The provisions of the regulation provide that out-of-state entities, by requesting ARB offset credits for an offset program that is not located in California, submit to jurisdiction in California. Additionally, linking to other WCI jurisdictions will be addressed through linkage agreements through a full public process in the future.

K-27. (multiple comments)
Comment: CARB's proposal to raise funds via an auction for reasons outside of administrative fee purposes is beyond CARB's regulatory authority. CARB justifies an auction system as a means of lowering GHG emissions and satisfying requirements under AB 32. CARB proposes that revenues from an auction be appropriated by the legislature for purposes of funding programs such as a community benefits fund, consumer rebates program and a low carbon investment fund. These and other proposed programs are outside the scope of administrative fees, and would likely be challenged as contrary to the legislative intent of AB 32. (CALCHAMBER1)

Comment: ARB's proposed Cap-and-Trade Rule appears to impose an unauthorized "regulatory fee" on electrical generators that cannot pass through GHG allowance costs. California law requires that any "levy, charge or exaction of any kind" be passed by a two-thirds majority of the Legislature (see Cal. Const., art. XIIIA). The recently passed Proposition 26 excludes a regulatory fee from the definition of a tax, but only if the charge is imposed for the reasonable regulatory costs to a state or local government for issuing licenses and permits; performing investigations, inspections, and audits; enforcing agricultural marketing orders; and the administrative enforcement and adjudication thereof. ARB has not established that the proposed uses of the revenue raised from the Cap-and-Trade auction are reasonably related to, or limited to, the administration of the Cap-and-Trade program. ARB has suggested such broad uses for auction revenue unrelated to administration of the program such as technology and community grants and ratepayer relief. Thus, the auction provision should be enacted by the Legislature, with a two-thirds vote, rather than be imposed by regulation by ARB. (HDPP2)

> **Response:** We believe that AB 32 provides ARB with the authority to conduct an auction as part of a cap-and-trade program. AB 32 authorizes ARB to "adopt a regulation that establishes a system of market-based declining annual aggregate emission limits for sources or categories of sources that emit greenhouse gas emissions" (Health and Safety Code section 38562(c); see also section 38570, which specifies additional criteria for market-based compliance mechanisms). These statutory provisions authorize ARB to adopt a cap-and-trade regulation and, in order to initiate a cap-and-trade program, emission allowances must somehow be allocated to participating sources. Thus, AB 32 directs ARB to "Design the regulations, <u>including distribution of emissions allowances where appropriate</u>, in a manner that is equitable, seeks to minimize costs and maximize the total benefits to California and encourages early action to reduce greenhouse gas emissions." (Health and Safety Code section 38562(b)(1); emphasis added.)
>
> There are a variety of ways to allocate allowances; they can be distributed free of charge, they can be sold at a predetermined price, they can be auctioned off with competitive bidding, or by another allocation method developed. AB 32 does not direct ARB to use any particular method to distribute allowances, and does not specify that some methods are allowed and others are not. Each method of distribution has pros and cons, and different methods will vary in their ability to meet the statutory criteria set forth in AB 32. Auctioning of allowances is one widely recognized method to distribute allowances, and is in fact the method that has been recommended by the Market Advisory Committee and many other economists. We believe that in authorizing ARB to distribute allowances, and requiring that market-based compliance mechanisms must meet certain criteria, the Legislature did not intend to forbid ARB from choosing this widely recognized distribution method. In other words, as the administrating agency charged with interpreting AB 32, ARB believes that AB 32 provides ARB with the authority to include auctions as a feature of a cap-and-trade program. Also, see the response to Comments K-12 and K-34.

Environmental Justice

K-28. Comment: Cap and trade will inflict disparate impacts on low income communities of color in California. Title 6 of the Civil Rights Act in 1964 prohibits any entity receiving federal funding from discriminating on the basis of, among other things, race. We will file a Title 6 complaint once this regulation becomes final. (NEWELL)

Response: ARB disagrees that the regulation will have the discriminatory impacts claimed by the commenter. As explained in the Initial Statement of Reasons and in the responses to other comments in this Final Statement of Reasons, we do not believe the regulation will result in disparate adverse impacts on low income communities or communities of color. We are aware of no valid basis for claiming that the regulation violates Title 6 of the Civil Rights Act, and the commenter has not provided sufficient information or analysis to further evaluate his legal theory.

Consideration of Alternatives

K-29. Comment: There's a court order that's controlling these proceedings. Judge Goldsmith of the San Francisco Superior Court has ordered that this Board may not take final action on this regulation until he issues his ruling in the scoping plan lawsuit. He has further ordered that the Board must consider his opinion and his decision if his decision involves a cap and trade component of the scoping plan. In that lawsuit, which is being heard on the merits on Monday, we've argued four main points about cap and trade and the scoping plan. The Air Resources Board failed to assess the maximum technological feasibility and develop cost effectiveness comparisons between direct reductions and market mechanisms, determine whether cap and trade would facilitate the achievement of the maximum feasible and cost effective reductions, consider the performance of other greenhouse gas reduction programs in other states and nations, adequately analyze alternatives to cap and trade in the functional equivalent document. (NEWELL)

Response: The lawsuit referred to by the commenter does not affect the Board's ability to take final action to adopt the cap and trade regulation. In this lawsuit, petitioners challenged ARB's adoption of the AB 32 Scoping Plan (not the cap and trade regulation), claiming that the Plan did not comply with various statutory requirements specified in AB 32, and that the environmental analysis prepared by ARB for the Plan did not meet the requirements of the California Environmental Quality Act (CEQA). The San Francisco County Superior Court issued a final decision on May 20, 2011. In its decision the Court denied almost all of petitioners' claims, but ruled in favor of petitioners on two CEQA challenges to the environmental analysis prepared for the Plan under ARB's certified regulatory program. ARB immediately appealed the trial court's ruling, and on June 24, 2011, the Court of Appeal issued an order staying enforcement of the trial court's ruling until such time as the merits of the case are decided by the Court of Appeal. Since the trial court's ruling has been stayed, it does not impede ARB's ability to adopt the cap and trade regulation.

Separate from the Court of Appeal proceedings, ARB has been working on a parallel track to address the trial court's concerns regarding the Scoping Plan's alternatives analysis. ARB staff prepared a revised alternatives analysis and released it for a 45-day public comment period on June 13, 2011. Staff then prepared written responses to all comments received. On August 24, 2011, the

Board held a public hearing at which the Board approved the revised alternatives analysis, made various CEQA findings, and readopted the Scoping Plan.

Federal Facilities

K-30. Comment: Without an explicit waiver of sovereign immunity, Western is not subject to state laws or regulations. Western understands ARB believes the Clean Air Act provides a waiver of sovereign immunity for its program. While section 118 of the Clean Air Act, 42 U.S.C. section 7418, provides a limited waiver of sovereign immunity and requires federal facilities to comply with federal, state, interstate and local requirements for the abatement of air pollution to the same extent as any nongovernmental entity, Western understands neither the U.S. Congress nor the U.S. Environmental Protection Agency (EPA) has approved a cap and trade requirement for greenhouse gases, including California's program. While Congress or EPA, in the near future, may decide to approve such programs, until such time, Western does not have authority to bind Congress, EPA or other federal agencies with jurisdiction over such matters. To avoid any potential conflicts with federal law, Western would recommend the ARB remove references to Western and other federal agencies from the draft order until such time as Congress implements (and the President signs) a greenhouse gas law or EPA approves the states program. Including Western and other federal agencies unnecessarily raise complicated legal issues that are unnecessary for the implementation of the ARB's program. (WAPA)

Response: See the response to Comment K-8.

Authority to Raise Revenue

K-31. Comment: AB 32 does not authorize CARB to raise revenue for purposes unrelated to administration of the program, and CARB has not shown in the statement of reasons that an auction to raise revenue is necessary for, or limited to, administration of the program. In fact, CARB staff suggests that the legislature appropriate auction revenues for very broad purposes related to technology development, community benefit, workforce training, etc. Unless and until CARB can justify that revenues are required for administration of the program, the revenue is a tax that requires a 2/3 vote of the legislature.

CARB staff suggests that auctions are required to avoid windfall profits, yet free allowance up to the benchmark automatically protects against such risk by ensuring that no entity receives more allowances than needed to operate their facilities. Because there is no real risk of windfall profits under this proposed allocation scheme, it is clear that the real purpose of the auction is to raise revenues for purposes unrelated to the cap and trade program as outlined above. (CMTA1)

Response: ARB disagrees with the commenter. Please see the response to Comment K-27.

K-32. Comment: We believe CARB has no current authority, under AB 32 or otherwise, to raise revenue for purposes unrelated to administration of the AB 32 program. CARB has not shown in the statement of reasons that an auction to raise revenue is necessary for, or limited to, administration of the program. In fact, CARB staff suggests that the legislature appropriate auction revenues for very broad purposes related to other purposes including technology development, community benefit, and workforce training, for example. In our view this exaction is not only unauthorized by AB 32, but it is also a tax that will require 2/3 vote of the legislature. (AB32IG, PLOTKIN)

> **Response:** ARB disagrees with the commenter that the cap-and-trade program is a tax. Please see the response to Comment K-27.

Commerce Clause

K-33. Comment: The proposed Cap-And-Trade rule also raises substantial and novel federal questions under the Federal Power Act and Commerce Clause. In adopting the Cap-And-Trade program, ARB is clearly attempting to address a global issue, which will significantly burden interstate and international commerce in electricity from the outset in 2012. More specifically, the Federal Power Act preempts states from regulating the transmission and sale of electric energy at wholesale in interstate commerce. See 16 U.S.C. section 824. ARB's proposed Cap-And-Trade program effectively regulates the transmission and sale of electric energy at wholesale in interstate commerce by imposing the cost of purchasing GHG allowances at auction on electric energy from HDPP, which is subject to the Federal Power Act as an "exempt wholesale generator." (HDPP2)

> **Response:** ARB’s authority to implement the cap-and-trade program on imported electricity is derived from AB 32’s requirement that ARB account for imported electricity in its mandatory reporting regulation so that emission associated with imported electricity are considered part of California’s statewide GHG emissions. Additionally, the original version of the regulation on which this comment is based has changed substantially to address these concerns.

K-34. Comment: One of the problems with inter-sector competition is that it will be essentially impossible to exclude goods and services from outside of California on the basis of their implied greenhouse gas emissions costs. However small the cost may be, the cost of goods and services made or performed in California will be higher than the cost of goods or services made or performed in other states. While this cost disparity already exists in many areas, the disparities will increase, and will increase disproportionately in certain sectors. The logical method of combating the loss of jobs and businesses is to impose some sort of tariff or fee on imported goods and services to account for the energy use outside of the state. But such tariffs or fees are likely to be illegal, as a result of constitutional and federal legal prohibitions on such barriers to out-of-state commerce. Applying product-specific fees to goods and services imported into the state on the basis of their imputed energy intensity would involve administrative burdens of unimagined scope. (HOR)

Response: ARB does not intend to impose administrative fees on any imported products. As part of the development of the cap-and-trade program we performed a careful leakage analysis and identified all industries that may be susceptible to emissions leakage. All industries that were identified as at risk for leakage will receive free allowances in the first compliance period. The mechanism for allocating allowances was designed to minimize the incentive to relocate production out of state. In this way cap and trade will achieve cost effective emissions reductions while fully minimizing leakage to the extent feasible. A complete description of this allocation approach is included Appendix K of the Staff Report.

K-35. Comment: Peabody Energy Company urges ARB not to adopt provisions in the proposed Cap-and-Trade regulations that would apply the regulations to electricity produced at generating stations located outside of California. These provisions run afoul of the Commerce Clause of the United States Constitution. Peabody understands the view of ARB staff that these extra-territorial provisions were mandated by the legislature in AB 32. Nevertheless, these provisions violate the Constitution and should not be adopted. (PEABODYENERGY)

Response: ARB is not applying regulations to generating stations outside of California; it is applying regulations to energy delivered into California to account for the carbon generated to meet California demand. ARB modified the regulations to make the point of regulation more clear. Specifically, ARB has modified language to make clear that the regulation only applies to electricity that is actually designated to be imported into California by adding language to section 95852(b) to specify how the compliance obligation applies to imported electricity from when it originates from specified sources or unspecified sources outside of California. Section 95852 applies only to first deliverers of electricity, whether they are generators or electricity importers. We also modified the definitions of electricity importers and of purchasing selling entities in section 95802 to precisely identify the entity that delivers electricity to its first point of delivery in California. ARB believes these changes address the potential Commerce Clause implications of the regulation.

K-36. Comment: ARB's proposed application of its Cap-and-Trade program to out-of-state sources through the importation standard cannot withstand scrutiny under the "virtual per se" test for three reasons. The importation standard "directly regulates … interstate commerce" (see *Brown-Forman*, 476 U.S. at 579). The standard directly penalizes and therefore restricts the importation of electricity generated at out-of-state facilities. Importers must, in essence, pay a tariff to California in order to import their product into the state, and that money goes right into the state's coffers. Under the Commerce Clause, states cannot levy tariffs on imports. See *West Lynn Creamery, Inc. v. Healy*, 512 U.S. 186, 194-96 (1994), which held that a Massachusetts state law requiring mill processors, including out-of-state firms, to pay a premium to a state fund that was then disbursed only to in-state producers was “effectively a tax which makes milk produced out-of-state more expensive,” and thus discriminated against out-of-state milk . (PEABODYENERGY)

> **Response:** California’s regulations neither apply to out-of-state sources nor discriminate against interstate suppliers. The regulations are not facially discriminatory as presumed in the comment. ARB has modified the regulations to better reflect the constraints of the Commerce Clause. Specifically, ARB has modified the regulation to only apply to electricity that is actually designated to be imported into California. The regulation treats all first deliverers in essentially the same manner. Section 95852(b) is modified to clarify the treatment of first deliverers. In all cases, first deliverers must pay the compliance obligation based on the emissions associated with the electricity when it is first delivered into the California electricity grid, regardless of whether it is delivered at a point of connection where an electricity generating facility connects directly to the grid (a busbar), or to a first point of delivery for electricity that has left another jurisdiction and entered California. ARB believes these changes address the potential Commerce Clause implications of the regulation.

K-37. Comment: Application of the Cap-and-Trade program to out-of-state sources constitutes improper extra-territorial regulation. See *Healy v. Beer Institute*, 491 U.S. 324, 333 (1989), and *Edgar v. MITE Corp*., 457 U.S. 624, 642-43 (1982), in which the Commerce Clause precludes the application of a state statute to commerce that takes place wholly outside of the State’s borders, whether or not the commerce has effects within the State. ARB has chosen to regulate emissions associated with electricity generated in another jurisdiction but consumed in California. Critically, the conduct that the Importation Standard seeks to affect is the production of greenhouse gas emissions occurring in other states and thus wholly outside the State’s borders. Although the electrons produced at these out-of-state facilities are imported into California, the state is obviously not concerned with the impact these electrons have once they enter the state. (PEABODYENERGY)

> **Response:** AB 32 requires ARB to account for electricity imported into California when formulating the GHG emissions cap, and therefore, to account for the same imports when determining which entities are subject to a compliance obligation.

K-38. Comment: The imported electrons do not cause any damage in California. The concern is the generation of greenhouse gases at the out-of-state facility, and that is why staff wishes to align the threshold for out-of-state and in-state facility emissions at 25,000 metric tons. Staff’s view may be logical, but the Importation Standard is an effort to affect conduct occurring wholly outside the state, and that is something California cannot do under the Commerce Clause. (PEABODYENERGY)

Response: The regulation is intended to affect conduct occurring within California and treats all First Deliverers equally. There is no attempt to regulate conduct outside of California.

K-39. Comment: Application of the program to out-of-state generation is virtually per se invalid because such application is economically protectionist in its purpose and effect. See *Bacchus Imports*, Ltd. v. Dias, 468 U.S. 263, 270 (1984), which found that a state legislation constitutes economic protectionism' may be made on the basis of either discriminatory purpose or discriminatory effect. In order to survive a challenge based on economic protectionism, California bears the burden of showing that its justification for a discriminatory law is "unrelated to economic protectionism." See *New Energy Co. of Ind. v. Limbach*, 486 U.S. 269, 274 (1988). California cannot meet this burden. (PEABODYENERGY)

Response: The comment does not explain how the regulation discriminates or is economically protectionist. The comment contains a legal opinion based on an unexplained premise which does support the legal opinion expressed in the comment. The undisputed purpose of the regulation is to reduce emissions in California, including by affecting behavior in California that may impact imported electricity use.

K-40. Comment: California has almost no in-state coal generation and no coal industry, but it is trying to dramatically increase in-state renewable generation. This renewable generation is more expensive than the out-of-state fossil generation with which it competes. Such in-state renewable generation is therefore at risk if California does not penalize out-of-state fossil generation. (PEABODYENERGY)

Response: The regulations do not discriminate or penalize out-of-state fossil generation. This comment attempts to create a justification (protection of renewable generation) for the commenter's interpretation of case law. There is no basis provided for either of the commenter's assumptions in this comment. California welcomes and encourages renewable energy both within and outside of California. It is unclear what the commenter is intending to imply.

K-41. Comment: As stated by the Supreme Court, a regulation addressing interstate commerce that gives regulated parties "who handle domestic articles of commerce a cost advantage over their competitors handling similar items produced elsewhere constitutes such protectionism" (see *Oregon Waste*, 511 U.S. at 106). Thus, California cannot force producers or consumers in other States to surrender whatever competitive advantages they may possess to give local consumers an advantage over consumers in other states. See *Brown-Forman*, 476 U.S. at 580; *see also* Baldwin v. G.A.F. Seelig, which found that the state of New York had no power to project its legislation into Vermont by regulating the price to be paid in that state for milk acquired there, because such regulation sets] up what is equivalent to a rampart of customs duties designed to neutralize advantages belonging to the place of origin". (PEABODYENERGY)

Response: This comment assumes, without explanation or reference to the proposed regulations, that the regulations force producers or consumers in other States to surrender competitive advantages. The regulations do not contain such discriminatory language, purpose, or effect. The alleged protectionism does not exist in the proposed regulations.

K-42. Comment: Given the steep trajectory of increases in international greenhouse gas emissions, the program will have no discernible effects on the overall level of greenhouse gases in the global atmosphere nor on the global climate. Moreover, California has other alternatives for addressing the global climate change issue, such as lobbying in Congress for adoption of what could be more meaningful national or international approaches to the issue. (PEABODYENERGY)

Response: AB 32 requires California to reduce GHG emissions. California is employing a wide-range of laws and regulations, in addition to the present cap-and-trade regulations, to achieve the AB 32 emissions reduction level.

K-43. Comment: The proposed regulation interferes with the free flow of electricity in wholesale markets, a business that is interstate in nature.

The Supreme Court has often noted that state regulation having an interstate effect is given particular scrutiny where there is a need for uniform interstate regulations. *See Milk Control Bd. of Pennsylvania v. Eisenberg Farm Prods.*, 306 U.S. 346, 351 (1939) ("This court has repeatedly declared that the grant established the immunity of interstate commerce from the control of the states respecting all those subjects embraced within the grant which are of such a nature as to demand that, if regulated at all, their regulation must be prescribed by a single authority"); *Morgan v. Commonwealth of Virginia*, 328 U.S. 373, 377 (1946) ("Where uniformity is essential for the functioning of commerce, a state may not interpose its local regulation"); *Southern Pacific Co. v. Arizona,* 325 U.S. 761, 774 (1945) (noting the "confusion and difficulty" that would attend the "unsatisfied need for uniformity" in setting maximum limits on train lengths); *Cooley v. Board of Wardens*, 53 U.S. 299, 319 (1852) (Commerce Clause prohibits States from regulating subjects that "are in their nature national, or admit only of one uniform system, or plan of regulation").

Perhaps no industry in the United States is more interstate in nature and needing of uniform regulation than the electricity industry. Electrons flow according to the laws of physics at the speed of light and do not respect state borders. Every electric company in the country is part of a larger powerpool and interstate grid in order to achieve the benefits of diversity, reliability and coordination. As the Midwestern and Northeastern blackout of 2003 demonstrates, local events on the grid can have instantaneous and cascading effects across large sections of the country. Balkanized state control of interstate transactions across the grid, with individual states controlling interstate power flows based on their own conceptions of what is in their own best self-interest, could have catastrophic impacts.

Weighing the large interstate impact of California's Importation Standard against its purely symbolic purpose leads to the inescapable conclusion that such standard cannot withstand scrutiny under the Pike balancing test and therefore violates the Commerce Clause. (PEABODYENERGY)

> **Response**: The comment alleges, without explanation, that the regulation interferes with the free flow of electricity in wholesale markets. The regulations treat all wholesale energy producers equally. The comment assumes a legal conclusion that is not supported by the non-discriminatory language in the regulations.

K-44. Comment: BPA appreciates that ARB has afforded BPA Asset Controlling Supplier status through the greenhouse gas reporting regulations (section 95102 (a)(15), 95111(b)(3), 95111(f), and in ARB's Cap and Trade regulations section 95802(a)(8)). However, BPA disagrees with ARB's suggestions in its greenhouse gas reporting rules and cap and trade rules that it has "authority" to regulate BPA and that BPA is "required" to comply (see section 95101(d)(5), 95102(a)(102), 95802(a)(59)). BPA wishes to make clear that BPA is participating in California's GHG reporting program and Cap and Trade program purely on a voluntary basis and BPA is not conceding that California has any jurisdiction over BPA. Sovereign immunity may prevent BPA (and similarly WAPA) from being subject to these regulations. Despite ARB's position that the Clean Air Act waives sovereign immunity, it is questionable whether that waiver would cover BPA because it is purely a marketer that is not engaged in an activity that discharges pollutants. Further, although BPA intends to voluntarily comply with these regulations, BPA is concerned that mandatory regulations could interfere with its existing contracts and conflict with the marketing scheme established by Congress in BPA's governing statutes. Because BPA is willing to voluntarily comply, it is not necessary for ARB to include these jurisdictional assertions in its rules. Doing so could unnecessarily raise complicated legal issues that are unnecessary to full and timely implementation of the greenhouse gases reporting rules and/or the cap & trade program. Accordingly, BPA urges ARB to modify sections 95101(d)(4) and (5), 95102(a)(102), and section 95802(a)(59) (same definition of "Electricity importers" as the definition used in section 95102(a)(102)) in one of two ways, either by simply deleting the unnecessary language entirely, or by modifying it. The following illustrate both options for each of the three sections:
Delete option for section 95101:

(d) *Electric Power Entities.* The entities listed below are required to report under this article:
- (1) Electricity importers and exporters, as defined in section 95102(a);
- (2) Retail providers, including multi-jurisdictional retail providers, as defined in section 95102(a);
- (3) California Department of Water Resources (DWR);
- ~~(4) Western Area Power Administration (WAPA);~~
- ~~(5) Bonneville Power Administration (BPA).~~

Modification option for section 95101:

(d) *Electric Power Entities.* The entities listed below are required to report under this article:

(1) Electricity importers and exporters, as defined in section 95102(a);

(2) Retail providers, including multi-jurisdictional retail providers, as defined in section 95102(a);

(3) California Department of Water Resources (DWR);

(4) Western Area Power Administration (WAPA), unless it voluntarily reports under these regulations;

(5) Bonneville Power Administration (BPA), unless it voluntarily reports under these regulations.

Delete option for section 95102:

(a) For the purposes of this article, the following definitions shall apply:

(102) "Electricity importers" are marketers and retail providers that hold title to imported electricity. For electricity delivered between balancing authority areas, the entity that holds title to delivered electricity is identified on the NERC E-tag as the purchasing- selling entity (PSE) on the tag's physical path, with the point of receipt located outside the state of California and the point of delivery located inside the state of California. ~~Federal and s~~State agencies are subject to the regulatory authority of ARB under this article and include ~~Western Area Power Administration (WAPA), Bonneville Power Administration (BPA), and~~ California Department of Water and Power (DWR). When PSEs are not subject to the regulatory authority of ARB, including tribal nations, the electricity importer is the immediate downstream purchaser or recipient that is subject to the regulatory authority of ARB.

Modification option for section 95102:

(a) For the purposes of this article, the following definitions shall apply:

(102) "Electricity importers" are marketers and retail providers that hold title to imported electricity. For electricity delivered between balancing authority areas, the entity that holds title to delivered electricity is identified on the NERC E-tag as the purchasing- selling entity (PSE) on the tag's physical path, with the point of receipt located outside the state of California and the point of delivery located inside the state of California. ~~Federal and s~~State agencies are subject to the regulatory authority of ARB under this article and include ~~Western Area Power Administration (WAPA), Bonneville Power Administration (BPA), and~~ California Department of Water and Power (DWR). Federal agencies, including Western Area Power Administration (WAPA) and Bonneville Power Administration (BPA), are not subject to these regulations so long as they voluntarily report under these regulations. When PSEs are not subject to

the regulatory authority of ARB, including tribal nations, the electricity importer is the immediate downstream purchaser or recipient that is subject to the regulatory authority of ARB.

Delete option for section 95802:

(a) Definitions. For the purposes of this article, the following definitions shall apply:

(59) “Electricity importers” are marketers and retail providers that hold title to imported electricity. For electricity delivered between balancing authority areas, the entity that holds title to delivered electricity is identified on the NERC E-tag as the purchasing- selling entity (PSE) on the tag’s physical path, with the point of receipt located outside the state of California, and the point of delivery located inside the state of California. ~~Federal and s~~State agencies are subject to the regulatory authority of ARB under this article and include ~~Western Area Power Administration (WAPA), Bonneville Power Administration (BPA), and~~ California Department of Water and Power (DWR). When PSEs are not subject to the regulatory authority of ARB, including tribal nations, the electricity importer is the immediate downstream purchaser or recipient that is subject to the regulatory authority of ARB.

Modification option for section 95802:

(a) Definitions. For the purposes of this article, the following definitions shall apply:

(59) “Electricity importers” are marketers and retail providers that hold title to imported electricity. For electricity delivered between balancing authority areas, the entity that holds title to delivered electricity is identified on the NERC E-tag as the purchasing- selling entity (PSE) on the tag’s physical path, with the point of receipt located outside the state of California, and the point of delivery located inside the state of California. ~~Federal and s~~State agencies are subject to the regulatory authority of ARB under this article and include ~~Western Area Power Administration (WAPA), Bonneville Power Administration (BPA), and~~ California Department of Water and Power (DWR). Federal agencies, including Western Area Power Administration (WAPA) and Bonneville Power Administration (BPA), are not subject to these regulations so long as they voluntarily participate under these regulations. When PSEs are not subject to the regulatory authority of ARB, including tribal nations, the electricity importer is the immediate downstream purchaser or recipient that is subject to the regulatory authority of ARB. (BONNEVILLEPWR)

Response: See the previous response to Comment K-8.

K-45. Comment: Section 95812(d)(2) should be deleted. Under section 95812(b)(2)(B), revised as described in the previous comment, the threshold for coverage of emissions from out-of-state specified sources is set at the same level set for in-state generating facilities: 25,000 or more metric tons of CO_2e per year. As noted on page IX-11 of the ISOR for the Cap and Trade Regulation, this comparable treatment of in-state and out-of-state facilities is necessary to comply with the interstate commerce clause. Section 95812(d)(2) (p. A-42) would upset this comparable treatment of out-of-state and in-state generating facilities by changing the emissions threshold for coverage of out-of-state specified sources from 25,000 metric tons of CO_2e to zero tons in 2015. No reason is given for this change, and it may be challenged under the interstate commerce clause. The same threshold should be applied to in-state and out-of-state facilities for the duration of the cap and trade program. Therefore, section 95812(d)(2) should be deleted. Apart from the inappropriate change of threshold, all other provisions in section 95812(d)(2) are contained in sections 95812(b)(2)(B) and (C). Thus, if the change in threshold is eliminated from section 95812(d)(2), the section is redundant. Furthermore, section 95812(d)(2) is improperly located as a subsection of section 95812(d). Section 95812(d) relates to suppliers of natural gas, RBOB, and distillate fuels as specified in section 95851(b) (p. A-61), not first deliverers of electricity. (SCPPA1)

> **Response:** We disagree. ARB does not believe this application violates the commerce clause. In 2015, all electricity generated in California and imported into California will include the cost of compliance. Because it is infeasible to directly apply the compliance obligation to very small electricity sources in California, such as home or small business natural gas micro-generation, the compliance cost for this electricity will be passed through in the natural gas price. Effectively, California electricity generators will pay the compliance cost even for a few hundred therms of natural gas or less. It is infeasible to import electricity from micro generators. In fact, data provided to the EIA indicates in combination with data on specified source electricity imports submitted by importers pursuant to MRR shows that almost none of the electricity imported from GHG emitting sources comes from power plants that emit less than 25,000 metric tons. In essence, electricity generation is treated the same both before and after 2015, regardless of the jurisdiction of its origin. Section 95812(d)(2) does not violate the commerce clause, and is necessary in order to treat in-state and imported electricity the same once all natural gas is subject to the compliance obligation starting in 2015.

Does Not Meet AB 32 Requirements

Comment: The proposed regulation fails to maximize environmental co-benefits to the extent feasible. Prior to adopting a Cap and Trade system under AB 32, ARB must, “to the extent feasible,” maximize additional environmental benefits to California where it is appropriate to do so. Health and Safety Code section 38570(b)(3). By using the term “feasible,” the Legislature signaled its intent to require ARB to demonstrate that all appropriate measures must be taken to maximize environmental benefits, unless those measures are shown to be impracticable.

AB 32 does not define the term “feasible.” However, that term has a specific meaning under other statutes, including the California Environmental Quality Act—a meaning of which the Legislature was presumptively aware when it enacted AB 32. “Feasible” means “capable of being accomplished in a successful manner within a reasonable period of time, taking into account economic, environmental, social, and technological factors.” Pub. Res. Code section 21061.1. In the CEQA context, when a lead agency rejects an alternative as economically infeasible, it must support that determination with quantitative, comparative evidence that the alternative would be economically impracticable (not just more expensive). See, e.g., Save Round Valley Alliance v. County of Inyo, 157 Cal. App. 4th 1437, 1461-62 (2007) (holding that applicant’s inability to achieve “the same economic objectives” under a proposed alternative does not render the alternative economically infeasible); Uphold Our Heritage v. Town of Woodside, 147 Cal. App. 4th 587, 600 (2007) (requiring evidence that comparative marginal costs would be so great that a reasonably prudent property owner would not proceed with the project); Preservation Action Council v. City of San Jose, 141 Cal. App. 4th 1336, 1356-57 (2006) (holding that evidence of economic infeasibility must consist of facts, independent analysis, and meaningful detail, not just the assertions of an interested party). Nor may a lead agency conclude that mitigation measures are legally infeasible without an adequate basis. As the Supreme Court put it, “[a]n EIR that incorrectly disclaims the power and duty to mitigate identified environmental effects based on erroneous legal assumptions is not sufficient as an informative document.” City of Marina v. Bd. of Trustees, 39 Cal. 4th 341, 356 (2006).

The Legislature’s use of the term “feasible” in connection with environmental co-benefits thus imposes a specific burden on ARB—a burden that the ISOR and FED fail to meet. For many months, the Center and other organizations have identified specific, appropriate measures to ARB staff (such as, for example, measures to ensure that forest offset projects improve forest management rather than perpetuate environmentally destructive practices) that could enhance, and thus help maximize, environmental co-benefits. Many of those measures are discussed again throughout this letter. At no point, however, has ARB demonstrated the infeasibility, or even the inappropriateness, of any of these measures. The Cap and Trade regulation as proposed thus fails to comply with AB 32. (CBD1)

> **Response:** The commenter states that ARB has not demonstrated that specific measures suggested by the commenter and other groups that could help maximize environmental co-benefits (such as measures to ensure that forest offset projects improve forest management) are infeasible as required by Health and Safety Code (HSC) section 38570(b)(3). The provision cited directs ARB to: “to the extent feasible and in furtherance of achieving the statewide greenhouse gas emissions limit…maximize additional environmental benefits.” (HSC 38570(b)(3).). AB 32 does not include a specific definition of “feasible” or criteria that should be used to determine what constitutes “to the extent feasible.” AB 32 leaves the specifics of how to do so, including balancing a variety of competing concerns, up to ARB. During development of the cap-and-trade regulation, ARB considered all of its statutory mandates under AB 32, including the requirement

to consider measures to maximize additional environmental benefits based on evidence, including economic analysis, where appropriate "to the extent feasible and in furtherance of achieving the statewide greenhouse gas emissions limit." The appropriate analyses are included within the ISOR for the regulation. ARB does not interpret AB 32 to require ARB to make a formal infeasibility determination regarding specific measures suggested by the commenter and other groups.

Development of the cap-and-trade regulation included extensive economic analysis and the involvement of an Economic and Allocation Advisory Committee. The updated economic analysis supporting the development of the regulation was prepared by ARB and released on March 24, 2010 (ARB 2010). Economic reasons were not cited for potential infeasibility of avoiding impacts from implementing the proposed Forest Offset Protocol. On pages 311 to 314 of the Functional Equivalent Document (FED), ARB explains that significant adverse biological impacts are not expected from implementing the Forest Offset Protocol, because sustainable, long-term harvesting practices and natural forest management would be required and project sites would be subject to some silvicultural activities with or without a Forest Offset Protocol project. Nonetheless, the FED discloses the risk that some adverse impacts cannot be entirely eliminated and unanticipated adverse biological impacts could occur. ARB cannot speculate as to the location of such impacts, but has committed to implementing an adaptive management approach as a program design feature that affords adjustment to the regulation if any unanticipated significant biological impacts occur. These limits are well defined in authorizing legislation for ARB's responsibilities, which do not include regulation of biological or other non-air related natural resources. See the responses to comments in section F. Co-pollutants.

CEQA aspects of this comment can be found in Appendix O of the Staff Report.

L. MARKETS

This section includes comments and responses about the carbon market created by the cap-and-trade program, and refer but are not limited to sections 95920–95922. Major topics concern the confidentiality, registration and accounts, market oversight and monitoring, and holding limits.

General

L-1. (multiple comments)
Comment: Sections 95922(a), 95922(b), 95922(d)(1) refer to "section 95930," which is not part of the proposed regulation. NCPA understands CARB intends to reference section 95830 regarding registration with CARB in these three sections addressing trading and banking of compliance instruments. (NCPA1)

Comment: Under paragraph (b) of section 95922, a reference is made to section 95930, which does not exist. (CAPCOA1, CAPCOA2)

> **Response**: We corrected the typographical error by modifying section 95922 to reference section 95830.

L-2. Comment: Regulations should clarify that industrial facilities can use allowances for compliance purposes: The regulations should clarify that industrial facilities receiving an allocation of allowances will be able to use the allowances for compliance purposes. Section 95891 provides for an allocation of allowances to industrial sector facilities. Unlike section 95892, which clarifies how IOUs and POUs use allocated allowances, section 95891 fails to clarify this use for industrial facilities. While the regulations allow a POU to distribute allowances from their holding accounts to their compliance accounts, IOUs are required to monetize all allowances immediately to "ensure that the amount of value given to distribution utilities is transparent to the public and that this value is used on behalf of electric ratepayers." (See Appendix J, at J-60) CARB's regulations should clarify, in section 95891, that industrial facilities can use allowances in a manner similar to POUs, particularly in light of the fact that the identified restrictions required for IOUs are not relevant to industrial facilities. Accordingly, two sections of the regulations should be modified. The following provision should be added to section 95891:

> <u>(d) At least 90 days prior to receiving a direct allocation of allowances, industrial facilities will inform the Executive Officer of the share of their allowances that is to be placed:</u>
> <u>(1) In the industrial facility's compliance account; or</u>
> <u>(2) In the industrial facility's limited use holding account.</u>

Section 95831(a)(3) should be modified as follows:

(3) Limited Use Holding Accounts. When an entity qualifies for a direct allocation under section 95890, the accounts administrator will create a limited use holding account for the entity that shall be subject to the following restrictions:

(A) the entity may not transfer compliance instruments from other accounts into the limited use holding account; and

(B) ~~the entity~~ an investor-owned utility may not transfer compliance instruments from the limited use holding account to any account other than the Auction Holding Account. (EPUC)

Response: We disagree with the suggested changes to section 95891(d) and section 95831(a)(3)(B). We believe it is clear in the regulation that the industrial covered entities could use free allowances deposited into their compliance accounts to fulfill their compliance obligations. Furthermore, industrial covered entities do not have a "limited use holding account." Therefore, there should be no confusion that industrial covered entities are like IOUs which are subject to the consignment auction requirements.

L-3. Comment: LADWP strongly supports policies that have been incorporated into the proposed regulation intended to help contain compliance costs including banking of allowances. (LADWP1)

Response: Thank you for your support.

Participation in the Market

L-4. Comment: In the EU we provide a facility for companies and individuals to buy and cancel emissions rights. We believe this is an important feature of emissions trading and one that should be preserved. Civil society should always have the right to enter the market to buy down the cap if it considers the volume of emissions rights granted to be too high to address adequately the risk of global climate change. (SANDBAGCC)

Response: We have added a provision in our regulation to allow voluntarily associated entities to participate the market. We also provide a mechanism for any registered entity to voluntarily retire compliance instruments.

L-5. Comment: Stringent regulations are essential to California's Cap and Trade program. Speculators bent on accumulating personal wealth will cloud the proposed goal of reducing emissions and therefore should absolutely not be allowed to participate. There is little time left. The goal is to create a system of operation more in tune with a healthy environment. The focus should be to reform local operations that create the pollution. If a cap and trade system is needed to help pay for the modifications necessary then these interactions should be highly scrutinized and transparent. To think of selling responsibility for reform elsewhere is unconscionable. (SIMS)

> **Response:** As detailed in the Scoping Plan, the cap-and-trade program is designed to work in concert with a number of complementary measures, such as standards for cleaner vehicles, low-carbon fuels, renewable electricity, and energy efficiency. We evaluated four alternatives, including additional source-specific regulations, and found that none were more effective than the implementation of a cap-and-trade program in carrying out the goals of AB 32. Staff has designed the program, including the cap, to be sufficiently stringent to spur GHG reductions to achieve AB 32 goals. We will closely monitor whether, over time, the cap-and-trade program is meeting the objectives set forth in AB 32.

L-6. (multiple comments)
Comment: Allow only stakeholders to trade in the allowance market. Speculative trading in commodity markets, such as crude oil, has unnecessarily driven costs higher, placing a large economic burden on companies that need to purchase these commodities for their operations. Any speculative price increases in the allowance market will exacerbate leakage and provide additional financial difficulties for stakeholders. Speculators will only be participating in order to make a profit; they do not need to purchase allowances for any other purposes. Speculators do not have risk associated with non-compliance, while stakeholders can incur significant costs due to non-compliance. Speculators do not necessarily participate in the California economy by providing products for Californians. Stakeholders businesses are located in California. (KERNOIL1)

Comment: We are concerned that the auction allows non-regulated entities to participate. These entities will have the ability to hold allowances for a profit therefore increasing the costs of the program. Hedge funds have already begun developing strategies for the offset market and could potentially be developing the same for the allowance market. There is a profit to be made by holding entities hostage to the allowance market. Other groups will have the ability to retire allowances and prevent the regulated entities continuing to operate in California because the allowances will not be available for purchase. (AGCOALITION)

Comment: Speculation is a risk-laden distraction from the purpose of the program: One would be entitled to ask why government funds are being spent to create and police a speculative market, the operation of which enriches financial gamblers—the same risk-for-profit actors who have just brought the global banking system near to collapse—and does nothing to decrease greenhouse gas emissions. In fact, the presence of this speculative market threatens clean development by creating artificial price fluctuations that have nothing to do with anything other than the vagaries of short-selling, complex and opaque financial instruments, and the irrational fluctuations that characterize stock markets. (MAGILAVY)

Comment: Markets do not plan and are unconcerned with equity or transparency: Relying on market forces to create clean development in the developing world removes that activity from any transparent public planning process that considers sustainability, equity, or regional economic need. (MAGILAVY)

Response: We are allowing non-covered entities to hold compliance instruments to ensure that the market prices instruments to reflect the likelihood that the price of instruments will increase over time. We expect that the covered entities will undertake the cheapest direct reductions early, undertaking more expensive reductions later. This increasing cost of direct reduction should lead to higher instrument prices over time. In an efficient market, the expectation that prices will be higher in the future should cause market participants to purchase and bank additional allowances early. This causes the prices to rise early in the program, signaling to market participants that they should be more aggressive in pursuing direct reductions.

We are concerned that excluding financial participants would prevent the market from giving a price signal that reflects expected future increases in the cost of direct emission reductions. Covered entities may not have the financial ability to purchase and hold allowances for later compliance periods. If we exclude financial participants, prices may not reflect anticipated future scarcity and covered entities will not receive the correct price signal supporting the need for additional current direct reductions. The correct price signal should lead to less volatile price changes over time.

While it is true that speculative participants do not have compliance risk, they do run the risk of financial loss if they overestimate the rate of price increases.

Finally, we have a number of regulatory provisions to deter market gaming, including prohibited practices, holding limits, purchase limits, and disclosure of corporate affiliations. At the direction of the Board, we will be contracting with an independent market monitoring service to help detect market manipulations. We are also establishing a Market Surveillance Committee composed of academic experts to provide advice on market design and oversight.

L-7. Comment: Cap and Trade is just a form of buying one's way out of reducing carbon use. Allowing speculation in such markets further removes the process from the goal of reducing carbon use. At the minimum California should remove speculation from its cap and trade program so that its effectiveness can be measured, and so that incentives for maintaining a program that will not work will be removed. (MONTE)

Response: Not all carbon emissions can be eliminated. We believe that the most effective means of reduction, after taking into account reductions obtained through various direct regulatory efforts, is through placing a clear price on carbon. This allows entities to choose the lowest-cost compliance method while California as a whole meets the emissions target of AB 32. The addition of financial participants is expected to reduce price fluctuations over time and give covered entities a clearer indication of the value of emissions reductions.

L-8. Comment: Paramount is also concerned about the ability of non-obligated parties to participate in California's carbon market. Speculators in the oil and gas markets have historically affected price and reduced the efficiency of the open market. Paramount recommends CARB limit the eligibility or participation of non-obligated parties so that influence on the carbon market unassociated with manufacturing or production can be minimized. (PMTPETRO1)

Response: We do not agree that financial participants have necessarily reduced the efficiency of oil and gas markets. There are usually multiple causes of market volatility. In the case of oil and gas markets, as cited in the comment, growth in demand worldwide and the failure of producing countries to keep up with this growth contributed to the recent price increases, while the financial meltdown and resulting economic recession led to rapid price decreases. No credible analysis has shown that speculators played a greater role in determining oil and gas market prices. The addition of financial participants is expected to reduce price fluctuations and give covered entities a clearer indication of the value of emissions reductions over time.

We are recognizing the concerns of covered entities through the design of holding and purchase limits. Both of these rule provisions grant greater flexibility to covered entities to accumulate and purchase at auction than they do to financial participants.

L-9. Comment: The ISOR notes that "if market manipulation or other illicit activities are detected, ARB will work with the appropriate authorities to initiate enforcement activity and, if necessary, reevaluate regulatory requirements to avoid future incidents." (ISOR, p. II-57) However, the proposed regulation does not address the monitoring mechanisms that will be employed, nor does it identify a market oversight agency, or process by which identified shortcomings will be immediately addressed and corrected. (NCPA1)

Response: We include provisions to prevent gaming or other activities that would compromise the effective functioning of the program. These include auction registration, transaction reporting, and certification requirements, as well as provisions that establish limits on the amount of allowances entities can purchase at auction or hold.

We will be undertaking program measures as part of program implementation to address market manipulation. We will establish a Market Monitor and a Market Surveillance Committee, both of which will serve important roles in overseeing market activity and producing regular publicly available reports. We are also working with both the State Attorney General and the Commodity Futures Trading Commission to ensure all necessary provisions are in place to monitor activity in secondary markets. We will pursue enforcement and strict punishment for those who do not comply with the regulation.

L-10. Comment: There will be increased inter-sector trading of allowances. This trading will cause competition among economic sectors to purchase available allowances (or offsets). The sector most able to pay for the allowances will win the competition. It is entirely foreseeable that certain industries with thin margins will be better off shutting their doors and selling their allowances than continuing to operate. Electric utilities, as observed above, will have significant competitive advantages in this inter-sector competition. (HOR)

Response: We believe the methods used to calculate the direct allocation of allowances to industry will address this problem. The lower margin sectors that would have more difficulty competing for compliance instruments will be the most emission-intensive and trade-exposed industries, which will be receiving the highest rate of direct allocation. Utilities may have a greater ability to pass on their compliance costs than in other industries, but the electricity sector faces greater emissions reductions requirements from the full AB 32 program than do the other sectors.

Program Start-up

L-11. Comment: This regulation places many requirements on regulated entities, which must be able to plan for and comply within a timely manner. Entities will be unable to do so without the necessary enabling compliance tools, guidance, and infrastructure (e.g., compliance instrument tracking systems, a registration process, verified offsets, adequate third party verifiers, IT systems, training, and a dispute resolution process) in place from the onset of this regulation. Recent regulations, such as the AB 32 administrative fee and LCFS, have relied on regulatory enforcement advisories to minimize enforcement exposure when compliance tools and guidance have not been provided in a timely manner. Such delays and uncertainties will unnecessarily increase costs and exposure to violations. CCEEB recommends that:

1) The ARB develop a work plan with a clear lists of tools, guidances, policies, trainings, and systems that they must develop, along with completion deadlines for each activity that must be in place for the regulated entities to comply. As this regulation is being developed, requirements should be explicit and transparent.
2) The ARB include a mechanism that links an entity's compliance deadlines directly to availability of theses compliance tools, allowing for sufficient lead time for facility compliance. (CCEEB1, CCEEB2)

Comment: In order to implement the LCFS and AB 32 Administrative Fee regulations, ARB has had to issue a series of enforcement waiver regulatory advisories because the necessary enabling tools were unavailable. We are concerned that there is potential for similar problems under the proposed cap and trade program. We believe that reliance on enforcement waiver regulatory advisories for this regulation could result in exposure to unnecessary costs and business disruptions. If ARB does not have the registration process, auction process, tracking system or benchmarking free allocation process in place in a timely manner, we may begin the cap and trade program without being able to fully participate in the trading/auction process or without fully understanding our obligations. In many cases, these tools, guidance, and/or infrastructure are incomplete or yet to be developed. Therefore, ARB should prepare a detailed work plan of all compliance tools, guidance, and infrastructure that is necessary for entities to comply with the regulation and completion deadlines. At a minimum, the work plan should include a schedule for development of the mandatory reporting tool, training, allowance holding and compliance accounts, registration process, tracking system, auction and free allowance allocation timeline. In addition, the work plan should specify which compliance requirements are affected by these tools, guidelines, and market infrastructure and should provide an extension period for compliance until the work plan item is fully developed. (WSPA1)

> **Response:** We will continue working to finalize the necessary elements of the regulation. However, in light of the importance of this regulation to the success of California's climate change program and the need for all necessary elements to be in place and fully functional, including training for cover entities, we are proposing to initiate the program in 2012, but start the requirements for compliance in 2013. This will not affect the stringency of the program or change the amount of emission reductions that the program will achieve, keeping us on track to meet the 2020 target required by AB 32.

L-12. Comment: While approximately 97 percent of allowances are to be initially allocated to industry (including over 50 percent to electric utilities) during the program's first compliance period (2012 through 2014,) this number decreases to 42 percent by 2020. Dow is supportive of the high initial allocation, but believes the 55 percent decline in allocated allowances in only six years is problematic. At the rate proposed by ARB, industry will find it very difficult to adjust to the increased costs of auction, threatening competitiveness, jobs and consumer energy prices. Significant time and capital investment are needed to meet long-term emission reductions goals and transition California to a lower-carbon economy. Dow recommends exponentially phasing in more auctioning over a longer period time, where initial auctions would be small and gradually increase at a steeper rate. This will help participants acclimate to the market, keeping costs down and improving efficiency.

> **Response:** The cap-and-trade regulation is designed to gradually transition from mostly free allowance distribution to a system in which most allowances are auctioned. This transition provides regulated sources time to get used to the market and the need to procure allowances. This approach gradually introduces a carbon price on goods that consumers purchase while simultaneously ensuring that emission reductions occur. We recognize that the long-term success of the program will require significant investment in emissions reductions. However, under current economic conditions, an early emphasis on auction could hamper the ability of California sources to invest in low-carbon technologies. Further, freely allocating allowances in the early years of the program will help prevent

leakage. Allocating the allowances for free using emissions efficiency benchmarks will reward companies that have already made investments in energy efficiency and carbon reductions, and will not penalize those that produce goods in California. The overall allocation approach includes: creation of an Allowance Price Containment Reserve for cost-containment purposes, a Voluntary Renewable Electricity reserve, free allocation to the industrial sector for transition assistance and leakage prevention, free allocation to electrical distribution utilities on behalf of ratepayers, and auction of the remaining allowances.

Trading, Reporting, and Confidentiality

L-13. Comment: IETA is concerned that the reporting provisions within the proposed rules are too broad in nature, and ultimately may have the unintended consequence of restricting liquidity of trading markets. The proposed draft regulations require the reporting of all "trades" of compliance instruments under the California program, but the proposal's ambiguity may present difficulty for ARB toward using this provision to adequately oversee the market. Proposed ARB requirements to report each trade will leave the Board with a large volume of trade data that will not properly represent holdings of compliance instruments, as positions will be modified considerably before actual delivery. IETA recommends ARB gather data only on trades as they go to physical delivery. In the case of spot transactions, this would be immediate. In the instance of OTC forward, futures, and options trades, this would be at the time of delivery under the terms of the contract. (IETA1)

Response: We agree with the comment, and we believe that the changes made to section 95921 address these comments. We anticipate further discussion with market participants in the area of trade reporting and confidentiality of information as ARB begins the process of linking with the other WCI jurisdictions.

L-14. (multiple comments)
Comment: ARB should not require reporting of trade pricing. ARB proposes to require market participants to report the price of trades, among other information. This requirement may restrict liquidity in the market, and perhaps run counter to federal derivatives trading draft regulations. In general, market participants consider the price of transactions to be highly confidential. In addition, reporting price information from individual trades is not feasible for regulated marketplaces, such as exchanges. These trading venues are prohibited from reporting this information per draft regulations established by the Commodities Futures Trading Commission. IETA also questions the need for ARB to gather price information from individual trades. This information is irrelevant to the enforcement of holding limits or to monitor companies for environmental compliance. Furthermore, price transparency for market participants, which is an essential element to a properly functioning market and for the operation of proposed cost containment mechanisms, can be obtained from existing sources, such as news outlets, exchanges, and market intermediaries (i.e. brokers), without divulging the price of individual trades. (IETA1)

Comment: The collection of trade data is sensitive, and IETA is concerned with the lack of clarity in the proposed rules on how the data would be used by ARB. If the full set of data becomes available to the public, IETA has concerns this could deter trading and put regulated entities at risk for market manipulation. IETA recommends that reported trade data not be made available to the public. Rather, ARB should consider making available to the public aggregate data on trading activity. In addition, the CFTC will have the authority to collect all of the carbon market transaction data for the purpose of regulating trading in these markets. ARB may want to consider establishing a formal information sharing relationship with the CFTC for the purposes of market oversight. IETA understands this recommendation to be the intent of ARB, and we encourage ARB to clarify this intent through modification to the final rule. (IETA1)

> **Response:** We have addressed these comments through revisions to section 95921. We will treat counterparty information reported to ARB on transfers as confidential; releasing only trade quantities and prices in a manner that will protect the identity of counterparties.
>
> We recognize that many agreements to transfer compliance instruments will not result in meaningful or reportable prices. We will provide guidance on complying with these provisions. We do not agree with the assertion that existing sources can provide the necessary price information. These sources are themselves subject to manipulation.
>
> As the commenter recommends, we do intend to work with the CFTC in combining information on markets regulated by the CFTC or by ARB. However, CFTC has advised us that it does not routinely collect information on markets outside of its direct jurisdiction. We will work with CFTC to prevent seams in market oversight, but it is clear that to do this ARB must collect extensive data on the primary and secondary markets. These coordination issues are program considerations that are not typically placed in regulation and resolved as part of program implementation.

L-15. (multiple comments)
Comment: More Clearly Define the Type of Transaction that is Reported: The proposed regulations require the reporting of all trades of compliance instruments under the California program. The use of the term "trade" may present difficulty to ARB in the acquisition of useful transaction data. Evolution Markets anticipates trading in California compliance instruments to be highly liquid and take place in a variety of venues, using a variety of products. Many of these transactions, such as forward and futures trades and derivatives (i.e. swaps and options) involve physical delivery of compliance instruments at some point in the future—if at all. (EVMKTS)

Comment: ARB should clarify what constitutes a “trade” in compliance instruments, and what it intends to do with the trade information it collects. Under the proposed regulations, ARB will collect detailed information about all “trades” involving compliance instruments. It is not clear what constitutes a “trade.” A straightforward approach would be for ARB to collect information on transactions in which compliance instruments are actually transferred from the account of one registered entity to the account of another. ARB should clarify whether it intends to make this information public and, if so, whether it will be disclosed in an aggregated form or in a form that provides information about specific transactions. Market participants generally see certain transactional information, such as price terms, as highly sensitive. Keeping such information confidential can be important for ensuring an efficient and competitive marketplace. (CERP1)

Comment: Proposed ARB requirements to report each trade will leave the Board with a large volume of trade data that will not properly represent holdings of compliance instruments, as positions will be modified considerably before actual delivery. Evolution Markets recommends ARB gather data only on trades as they go to physical delivery and transfer within the ARB-established registry system. (EVMKTS)

Comment: Section 95921 requires disclosure of transaction information. We understand that certain information disclosure is needed by ARB because the system of accounts maintained by the accounts administrator is the final record of who owns each compliance instrument and additionally, ARB needs to be able to determine if a transaction would result in an account holder exceeding the holding limit.

However, it is not necessary for a market participant to report every transaction for ARB to enforce allowance holding limits. When the trade settles, and allowances are transferred, the registry would be able to ascertain if the buyer has exceeded any holding limit at that time. Therefore, it is not necessary to report a transaction when the trade is executed.

In addition, it does not make sense to require reporting of all transactions for the simple reason that many transactions will be made on a financial basis (i.e. settled with cash and with no ultimate physical delivery of allowances) and in jurisdictions outside of California. ARB would have no ability to enforce reporting of such transactions, resulting in an unfair reporting burden on compliance entities subject to ARB penalties. In addition, ARB would have an incomplete data set on transactions that may not reflect market conditions.

We recommend that Section 95921 be amended to apply only to transfers of allowances, and not the actual transaction itself. (SHELLENERGY)

Comment: Restrict Dissemination of Trade Date to the Public: The data requested by ARB, either the broad trade data interpreted above or a more restrictive interpretation as transfer data only, would include elements considered proprietary by market participants. Specifically, counterparties rarely allow information on the timing, size or price of their trades to be made public based on competitive concerns, and the availability of such information can make market manipulation in some cases easier to achieve. Requirements to submit such data to the regulator, and the potential for this data to be made available to the public, may also inhibit market liquidity.

The proposed rule does not indicate what data, if any, will be made available to the public. Evolution Markets recommends that reported trade data not be made available to the public. As necessary, ARB can market available to the public aggregate trade data. (EVMKTS)

> **Response:** We agree and have made revisions to section 95921 to remove the references to "trades" in the reporting requirements. Instead, we are using the term "transfer request" when referring to a document submitted to the accounts administrator indicating that counterparties have agreed to transfer allowances between their accounts and requesting that the transfer be recorded into the market tracking system. The confidentiality of the transfer is preserved through the provisions treating holding account balances and trade counterparties as confidential. In addition, only transactions that result in a request for transfer between tracking system accounts would be reported. For example, financially settled contracts would not be reported.

L-16. (multiple comments)
Comment: Sections 95920 and 95921 of the proposed rules stipulate that trading counterparties must be disclosed to ARB, and all trades must be reported within three days of the transaction. Evolution Markets fully supports ARB's goal of market transparency, and its ability to monitor the trading market in order to enforce holding limits and ensure environmental compliance. However, Evolution Markets recommends ARB provide further detail in the regulatory language on what types of information will be reported and how the Board may use this information. Without such clarifications, the trade reporting rules may have the unintended consequence of restricting liquidity in trading markets. (EVMKTS)

Comment: Section 95921(b)(6) requires reporting of prices and Section 95921(b)(4) requires reporting of the date and time of a particular transaction. This presents some logistical challenges, as allowances are fungible, and will be held in inventory on an aggregate basis. In addition, there are commercial and competitiveness concerns with reporting prices.

Shell Energy considers the price of individual transactions to be strictly confidential. Knowing a competitor's previous pricing strategies can put that company at significant disadvantage in future commercial negotiations. In addition, the price for any particular transaction is just one component of a deal, and a somewhat misleading figure without an understanding of the risks and obligations of the two transacting parties. Accordingly, Shell Energy does not agree that this data should be required by ARB.

Many IT systems do not capture the time of a transaction, as it is often not pertinent commercial information. Requiring this information to be captured and reported would result in excessive costs on businesses having to comply with these reporting regulations.

We believe that ARB can achieve their objectives to monitor prices by allowing private companies to establish exchanges on which allowances and offsets can be traded. Liquid trading of standard exchange-based products is the best means of achieving price transparency in a traded market.

We recommend that Sections 95921(b)(6) and 95921(b)(4) be deleted. (SHELLENERGY)

> **Response:** ARB addressed these comments through revisions to section 95921. ARB will treat counterparty information reported to ARB on transfers as confidential; releasing only trade quantities and prices in a manner that will protect the identity of counterparties.
>
> ARB recognizes that many agreements to transfer compliance instruments will not result in meaningful or reportable prices. ARB will provide guidance on complying with these provisions. In addition, ARB has removed the requirement to disclose a time for the underlying transaction and settlement, as ARB agreed with the comments below from MSCG2 that this requirement is unnecessary.

L-17. Comment: The date and time of the transaction agreement may be problematic. This information is not necessarily captured and retained by existing reporting systems designed for reporting to the CFTC, and the utility of that datum in preventing market manipulation or fraud seems minimal at best. We recommend that date and time reporting for transactions not be required. (MSCG2)

> **Response:** ARB agrees with part of the comment and has removed the requirement to report the time of a transaction or settlement. ARB has retained the requirement to disclose a date as useful for monitoring the market and evaluating holding limits.

L-18. Comment: CARB should require that all trades (with the possible exception of offset initiation contracts or the first sale of an offset contract) be cleared by federally regulated clearing organizations. (EDF1)

> **Response:** ARB considered this approach, but there are too many uncertainties concerning ARB's authority to regulate all trading venues in this manner.

Registration, Accounts, Market Monitoring and Holding Limits

L-19. Comment: Deadlines should be established for ARB decision-making processes to provide entities with a degree of certainty. Modify section 95830(e) as follows:

> (e) Completion of Registration. Registration is completed when the Executive Officer approves the registration and informs the entity and the accounts

administrator of the approval. <u>The executive officer shall approve or deny a registration application within 30 days of submittal.</u> (CCEEB1)

Response: We did not make this change, as there is already a general requirement that state agencies respond within 30 days when there is an expectation of response, unless specified otherwise in a specific regulation.

L-20. Comment: Clarification is needed in regards to what type of relationship constitutes "beneficial ownership." We recommend that "beneficial ownership" regulations only apply to circumstances where the nominal owner has an arrangement with a third party whereby that third party can direct the owner as to how to act with the allowances acquired on its behalf. (MSCG2)

Response: We agree that "beneficial ownership" needed clarification. We modified the regulation by deleting section 95915 and adding new section 95834 (Disclosure of Beneficial Holding). New section 95834 provides detailed provisions that any entity holding compliance instruments on behalf of another entity disclose the relationship to ARB. New section 95921(e)(1) defines when a beneficial holding relationship exists and when the requirements of 95834 will apply.

Section 95834(a) describes the participants in a beneficial holdings relationship, defining an agent as an entity holding allowances owned by a second entity, which is defined as the principal. Section 95834(b) contains requirements for the disclosure of beneficial holding relationships. This section requires that both agent and principal confirm the existence of a relationship, as well as any transfers made as a result of that relationship. Section 95834(c) contains requirements applying to an entity which may serve as an agent for more than one principal. The requirements are intended to prevent the disclosure of market information between market participants, to prevent opportunities for collusion.

L-21. (multiple comments)
Comment: We do not oppose transaction price reporting to the Regulator. However, it is likely that many types of transactions will not have a specific price. For example, allowances may be transferred to a compliance entity by a service provider as part of a broader-based services arrangement, where there is no price explicitly stated for the allowances. Another example is where a transaction is part of a non-like exchange—say, 1000 California emissions allowances swapped for 100 crude oil futures. The Regulation Order needs to either exempt these types of transactions from price reporting, or develop explicit rules for how a price is to be calculated and reported. (MSCG2)

Comment: We do wish to emphasize that carbon credit transactions are often structured in complex and customized formats by entities that are comparatively thinly capitalized and without traditional access to exchanges and clearinghouses. We thus urge caution when designing market oversight rules regulating over-the-counter transactions between market entities and offset project developers, as in many cases these transactions cannot be replicated or placed on an exchange. Project developers and market entities need the flexibility to be able to enter into highly customized, private transactions that are conducted bilaterally, and these types of transactions do not pose a systemic risk to the functioning of the broader market. (CLIMATEWEDGE)

> **Response:** ARB acknowledges that for some underlying transactions, such as derivatives contracts, the reported price may not convey complete information about the value of the transaction. However, that is not true for all transactions, with standardized contracts trading on exchanges being one example. In addition, ARB sees no evidence that that reporting this information will prevent market participants from entering into more complex transactions as suggested in comment.

L-22. Comment: In section 95832(a)(3) (p. A-53) as well as other sections of the Cap and Trade Regulation, there are references to entities having an “ownership interest” in compliance instruments held in the account of other entities. It is unclear what form of “ownership interest” an entity can have in instruments that exist only as serial numbers in an account belonging to another entity without property rights attaching to the instruments. The references to “ownership interests” should be reconsidered. Although third party “ownership interests” are recognized in section 95832(a)(3), they are not recognized, for example, in section 95857(c)(3) (p. A-72), which allows the Executive Officer to remove instruments from the account of an entity with excess emissions without regard to whether those instruments may in some sense belong to a third party. (SCPPA1)

> **Response:** The references to "ownership interests" refers to any participating entity’s right relative to other private parties to direct the use of allowances or offset compliance instruments held in accounts in the California cap-and-trade program. As clearly stated in Section 95820(c), "[a] compliance instrument issued by the Executive Officer does not constitute property or a property right." The mention of "ownership interests" in Section 95832(a)(3) and elsewhere is not intended to and does not alter this fundamental characteristic of compliance instruments. Further, the terms "Allowance," "ARB Offset Credit," and "Compliance Instrument" are defined in Section 95802. Lastly, the commenter's concern regarding section 95857(c)(3) of the October 2010 Proposed Regulation is moot, as that section has been modified in the regulation approved by the Board.

L-23. Comment: As designed, the Allowance Reserve does not provide true long-term cost containment. At the beginning of the program, the Allowance Reserve will be fully populated with allowances drawn from future compliance periods. Thus, in the early years of the cap-and-trade program, covered entities should be able to meet allowance shortfalls with purchases from the first tier of the Allowance Reserve. However, because the allowances filling the Allowance Reserve are pulled from under the cap, compliance entities will eventually have to use them. Thus, over time, the availability of sufficient reserves in any of the tiers to meet market demand becomes less and less certain. In the long term, the Allowance Reserve will only increase the prices of allowances. At best, the Allowance Reserve can only delay cost increases. CARB should develop a mechanism to populate the Allowance Reserve without reducing the number of allowances available for distribution or auction.

For example, SCE believes CARB should populate the Allowance Reserve by using the proceeds from reserve procurement to purchase emissions offsets. In the alternative, CARB could develop detailed rules stipulating that the Allowance Reserve be replenished with additional compliance instruments once a predetermined number of reserve instruments have been purchased. This would create stronger assurances to regulated entities that the Allowance Reserve will always be available as a source of compliance instruments and can operate as a true long-term cost containment mechanism. (SCE1)

> **Response:** The Reserve does not lead to higher prices over time because the allocation of allowances to the reserve is "backfilled" through an increase in the offset quantitative use limit from four to eight percent. Had the backfill not been added, then the comment that creation of the reserve provides no price relief may have been correct.
>
> ARB considered the purchase of offsets to fund the reserve, but there were too many concerns with ARB intervening in the market by choosing which offsets to purchase, as well as questions over whether ARB could use auction proceeds in this manner. Finally, as explained in the Staff Report, ARB made the policy decision to avoid the institution of a hard price cap. Replenishing the reserve with an unlimited number of compliance instruments would result in a hard price cap.

L-24. Comment: Establish a contingency plan to address potential market failure. Dow is concerned about the rapid decline in allocated allowances. To address potential depletion of the allowance price containment reserve, Dow supports proposals that revenues from the reserve allowance auction be used to refill the reserve with Reducing Emissions from Deforestation and Forest Degradation ("REDD") offset credits.

> **Response:** ARB considered the purchase of offsets to fund the reserve but there were too many concerns with ARB intervening in the market by choosing which offsets to purchase, as well as questions over whether ARB could use auction proceeds in this manner. Finally, as explained in the Staff Report, ARB made the policy decision to avoid the institution of a hard price cap. Replenishing the reserve with an unlimited number of compliance instruments would result in a hard price cap.

L-25. Comment: Strategic reserve created to moderate supply of permits is a very welcome design feature that helps to maintain control over the supply of permits in the event of unforeseen circumstances. A market with variable demand but fixed supply is at risk of price crashes and spikes and the proposed reserve is a sensible suggestion for mitigating these risks. We consider the overall balance of supply and demand in the proposed system is such that it is far more at risk of price crashes than spikes and that it is unlikely that the reserved allowances will be bought. (SANDBAGCC)

Response: No response needed.

L-26. (multiple comments)
Comment: In the event additional and adequate supply of compliance instruments is not immediately available, Dow supports the development and inclusion of a mechanism in the regulation that allows ARB to temporarily suspend the cap-and-trade program and the entities' associated compliance responsibility until cost containment mechanisms are fully developed and functioning in a manner that fulfills their intended purpose. (DOWCHEM1)

Comment: Under higher economic growth, reduced offset supply, and lower than expected efficacy of complementary measures, the allowance reserve could become entirely depleted. Dow agrees that ARB should "establish a formal review process that would include monitoring the allowance market for potential market failures or unsustainably high allowance prices, and develop a contingency plan that could be implemented should the allowance reserve approach low levels." Any additional allowances that may be necessary to fortify or replenish the allowance reserve ought not to come from EITE entities. According to PG&E's written comments, PG&E commissioned Charles River and Associates ("CRA") to analyze a range of scenarios in an effort to understand the circumstances under which the allowances in the reserve might become depleted. CRA analyzed the sufficiency of allowances in the containment reserve under different assumptions about economic activity (including economic growth, demand for electricity, and emissions growth in the non-electric sectors), offset supply, efficacy of complementary measures, and unforeseen events. Under ARB's business as usual forecast for economic activity, (including ARB's assumptions for offsets), CRA concluded that under certain plausible circumstances the allowance reserve reached a critically low level or was depleted entirely. Specifically, under higher economic growth, reduced offset supply, and lower than expected efficacy of complementary measures the allowance reserve was depleted entirely. Dow shares PG&E's concern regarding the potential depletion of the price containment reserve. (DOWCHEM1)

Comment: In a letter to the ARB on May 17, 2007, regarding Proposed Early Actions to Mitigate Climate Change in California, CCEEB stated, "that it is important to view the market mechanisms as a continuum that continually examines the economic impact of the program and allows for realistic turnover of capital investments." CCEEB suggested that, "[ARB] consider recommending additional details surrounding the implementation of the cap-and-trade program in its report so that any market system failure can be properly mitigated with as minimal impact to the California economy as possible. This detail should include identification of the criteria and data that will be needed to determine that there is a working market and the information that needs to be tracked to identify market system failures before they cause significant harm." (CCEEB1)

> **Response:** Board Resolution 10-42 instructed staff to monitor depletion of the reserve, determine the cause, and make recommendations for corrective actions. The Board resolution did not specifically include temporary suspension of the cap-and-trade program. We will be investigating a number of options in responding to this direction from the Board. We will continue to evaluate if such a mechanism is needed, triggers for action, and types of potential responses. In the event of some catastrophic problem, the Executive Officer does have authority to issue emergency regulations to address the issue. Additionally, we will establish a Market Surveillance Committee to monitor the market and provide timely recommendations to the Board on market performance or any potential issues.

L-27. (multiple comments)
Comment: It is imperative that the State monitor leading indicators that reflect the economic health of California. CCEEB recommends that the ARB include provisions in the cap-and-trade regulation to: (1) monitor specific economic indicators, including cap-and-trade market elements, such as, the price in the quarterly auctions, the functioning of secondary markets, adequacy of the Allowance Price Containment Reserve, detection of market manipulation, offset supply, evidence of contract shuffling, progress towards achieving the 2020 target, total cost of the program, jobs in manufacturing, vacancy rates, home sales, volume of trade through ports, GSP, energy prices, and other indicators used by the Department of Finance to monitor the health of California's economy; (2) establish formal reviews of the regulation at least once each compliance period; and (3) develop and implement a more structured process and approach for evaluating the comparative cost-effectiveness of program measures, as well as the relative cost-effectiveness of those measures vis-a-vis the cap-and-trade program and identify any potential problems. (CCEEB1, CCEEB2)

Comment: ARB recognizes in the ISOR that effective market oversight is a necessary component of GHG cap-and-trade compliance programs. The proposed regulation notes that unanticipated effects and results could occur over the life of the program. While ARB proposes periodic reviews, the ARB should also establish a market oversight committee that meets regularly to assess whether the market is functioning as expected. This committee, similar to the one that reviews CAISO markets, should make recommended changes to the program to ARB on a periodic basis and be able to recommend that the Governor suspend the program if the market fails, creating unforeseen and harmful impacts to consumers. (SEMPRA1)

> **Response:** We agree and are establishing a Market Surveillance Committee (MSC) patterned in large part after the MSC created to advise the CAISO. The MSC will consist of a group of academic economists with experience in market monitoring and detection of market manipulation to assess market design and operation.

The MSC will have several important functions. First, it will periodically review the market's structure and operation and provide recommendations for improvement. Second, it will review market events and trends based on analysis and data provided by us. Third, it will convene scheduled public meetings to give market participants the opportunity to raise market issues to the MSC. Finally, the MSC will report any findings or recommendations to the Board as needed.

The Board Resolution 10-42 instructed us to perform monitoring and evaluation functions very similar to those suggested in comments. We will be contracting with an independent market monitoring service. This contractor will also provide a periodic review of how the system is functioning. The Board has also directed staff to continually monitor several program features of concern, such as leakage and depletion of the reserve. The cost-effectiveness assessment requested in the comments is beyond the scope of the current rulemaking effort.

L-28. Comment: CCEEB recommends that an Independent Market Monitor be established with authority to: (1) review bids prior to the running of any auction; (2) provide analysis of the competitiveness of any auction, preferably on an ex-ante basis (e.g. prior to running the auction); and (3) report findings and concerns to the ARB and the California Senate Energy, Utilities and Communications Committee. (CCEEB1)

Response: ARB intends to contract with an independent market monitoring service provider. On September 8, 2011, ARB released a Request for Proposals (RFP) for contract proposals from market monitoring service providers. The RFP proposes market monitoring functions that should address the concerns raised by CCEEB and perform the functions recommended by CCEEB.

L-29. Comment: While utilities have certain actions that they can take to help protect their customers and ratepayers from market fluctuations, they also need the certainty that the market in which they are operating also has such protections in place. As currently drafted, the proposed regulation does not contain sufficient information regarding the administration, operations, or oversight of the proposed auction. While subarticle 10 of the proposed regulation includes information regarding the auction design and the sale of California allowances, including information regarding auction administration and registration, aside from general references to the oversight of the Executive Officer in section 95912(a), there is insufficient information regarding the specific market oversight body or market monitoring entity that will oversee the day-to-day administration of the program. It is imperative that the regulation include specific provisions regarding market design and program oversight within the regulatory language, including potential impacts and interactions with the secondary market. The program should include provisions for testing the efficacy of all auction functions, including bid monitoring and tracking platforms, and registration and tracking of auction participants prior to implementation. The Board should also direct staff to conduct pre-implementation training and workshops, which would include a run-through of all market and auction operations. It is important that California not repeat the mistakes of the past and that this market-based mechanism not be implemented until it has been fully tested and deemed ready. (NCPA1)

> **Response:** ARB has taken steps to address these issues in response to the Resolution 10-42 adopted by the Board on December 16, 2010. ARB has taken steps to contract with an independent market monitoring service to maintain the integrity of the market. ARB is developing a Market Surveillance Committee to provide an ongoing source of expert analysis in market operations.
>
> ARB is also developing a market simulation capability. This activity will provide input to the program testing prior to the first auction. In addition, contract RFPs for auction, reserve sale, registry, and financial services will all have provisions for testing prior to operation.

L-30. Comment: The ISOR notes that "if market manipulation or other illicit activities are detected, ARB will work with the appropriate authorities to initiate enforcement activity and, if necessary, reevaluate regulatory requirements to avoid future incidents." (ISOR, p. II-57) However, the proposed regulation does not address the monitoring mechanisms that will be employed, nor does it identify a market oversight agency, or process by which identified shortcomings will be immediately addressed and corrected. (NCPA1)

> **Response:** We include provisions to prevent gaming or other activities that would compromise the effective functioning of the program. These include auction registration, transaction reporting, and certification requirements, as well as provisions that establish limits on the amount of allowances entities can purchase at auction or hold.
>
> We will be undertaking program measures as part of program implementation to address market manipulation. We will establish a Market Monitor and a Market Surveillance Committee, both of which will serve important roles in overseeing market activity and producing regular publicly available reports. We are also working with both the State Attorney General and the Commodity Futures Trading Commission to ensure all necessary provisions are in place to monitor activity in secondary markets. We will pursue enforcement and strict punishment for those who do not comply with the regulation.

L-31. (multiple comments)
Comment: Effective market oversight is a necessary component of GHG cap-and-trade compliance programs. Further, "ARB will regularly (at a minimum, once every three-year compliance period) evaluate whether the objectives identified by the stature are being achieved." DRA supports this program monitoring, however also believes that ARB should establish a market oversight committee that meets regularly to assess whether the market is functioning as expected. The committee should be comprised of market experts with experience in market monitoring activities and could include members from ARB, the CPUC, the CEC, and CAISO. DRA recommends that this

committee be given the authority to suspend the program or recommend that the Governor suspend the program if allowance prices remain unacceptably high, if the program is not achieving the objectives as defined by AB 32, or if the program results in unforeseen and harmful impacts to consumers. (DRA)

Comment: Program evaluation market monitoring and surveillance provisions should be added. The staff report states that CARB will evaluate the program every three years and make adjustments as necessary. Evaluation of the program periodically is appropriate but there are no specifics as to what portions of the program will be evaluated and what situations would trigger adjustments to the regulation. This creates much regulatory uncertainty and makes it difficult for entities to plan for compliance. LADWP recommends that the ARB include a provision in the regulation related to market monitoring and surveillance and program evaluation. This provision should provide a full assessment of the cap-and-trade program's performance and market operations. It should also clearly define what would trigger possible amendments to the regulation (e.g. price of allowances reach a certain level during a specified time period number of offset credits available drops below a specified level). LADWP recommends that such provisions for program evaluation market monitoring and surveillance be included directly in the regulation and not just in the staff report. (LADWP1)

> **Response:** The monitoring within compliance periods referred to in the Comments refers to achievement of AB 32 environmental goals. ARB is planning extensive market monitoring. In addition, the Executive Officer has the authority to issue temporary emergency regulations to make changes to the existing cap-and-trade regulations that would address any serious issues arising in the market. These could deal with unforeseen operational issues. However, a decision on when to revise a regulation is strictly up to the Board, and cannot be left to an independent committee, staff discretion, or a regulatory provision.

L-32. (multiple comments)
Comment: To ensure GHG reductions are achieved while maintaining the competitiveness of California businesses and the health of the economy, it is critical for CARB to monitor key indicators of not only the GHG reductions that are occurring but also indicators of the health of California's economy. We urge CARB to identify and monitor these key indicators, so that any inadvertent problems that may occur can be corrected before significant damage is done to California economy or environment. (CALCHAMBER1)

Comment: The Board's resolution should provide for a prompt independent market evaluation to test areas of potential market vulnerability, including the role of linkages, offsets, anticipated demand response and the functioning of the auction and price containment reserve and for the staff to return to the Board with proposed program revisions, as warranted. (CCC, MAZOWITA)

Comment: The Air Resources Board should create an independent market monitoring board responsible for monitoring the market and auction on a quarterly basis and recommending corrective action if needed. (BCFSE)

> **Response:** As directed in Board Resolution 10-42, we will contract with an independent entity with appropriate expertise that will monitor and provide public reports on a quarterly basis on the operation of the market, including auctions and reserve sales, and recommend appropriate action. ARB is establishing a Market Surveillance Committee to provide expert advice on monitoring trends and program revisions. We will evaluate the reports from both these groups, along with staff analysis of underlying market supply and demand conditions, in developing recommendations to the Board. These recommendations may include corrective action if all allowances are sold from any tier of the reserve.
>
> Board Resolution 10-42 also directed staff to work with the California Energy Commission, the California Independent System Operator, and others to monitor the cap-and-trade market, including the effect of the cap-and-trade program on the State's energy markets.

L-33. (multiple comments)
Comment: As currently written, adequate allowances could not be held by a compliance entity, such as Shell, to cover their obligations or to mitigate unacceptable price exposure. This problem is exacerbated during the 2nd compliance period when transportation fuels are included under the cap. Because of the large quantity of allowances that entities like Shell must surrender, we must have the flexibility to hold and trade sufficient allowances to meet our compliance obligations and minimize unacceptable risks. Entities that have compliance obligations should be permitted to hold a number of allowances in their registry account equal to at least 3 times their rolling future annual average emissions obligations, to correspond with the 3-year compliance periods. Otherwise, an entity would be prevented from managing its price exposure for the full compliance period. The "rolling" aspect of the proposal is necessary to manage the step change in compliance obligation that occurs between the 1st and 2nd compliance period when transportation and commercial/residential fuels are added to the cap. An estimate of this future obligation could be calculated using data from previously reported years. For the purposes of calculating an entity's holding limit, that entity should be able to include any emissions obligations of its affiliates, and any contractual emission obligations of those entities. An entity should also be able to transfer allowances and offsets freely between its general account and its compliance account. Otherwise, allowances bought by a compliance entity and moved to its compliance account (in order to take advantage of the compliance entity holding limit exemption) would suffer extreme financial loss if prices suddenly fluctuated. (SHELLENERGY)

Comment: The proposed holding limit, which translates to roughly 6 MMT, is far too low for a three-year compliance period for large compliance entities such as SoCal Gas, even with the limited exemption that does not count the allowances in the compliance holding account. It would essentially eliminate banking by those entities. While such holding limits are appropriate for entities without a compliance obligation, the holding limits should be increased for compliance entities. One approach would be to make the holding limit a function of the cumulative Annual Allowance Budgets within the three-year compliance period (e.g., year 2 holding limit based on the sum of year 1 and year 2 allowance budgets) for compliance entities.

Modify section 95920(b)(3) as follows:

Calculation for compliance entities: The holding limit will be calculated and applied within each compliance period using the following formula:

$$\text{Holding Limit} = \underline{\sum_{i=1}^{t}}[0.1*\text{Base} + 0.025*(\text{Annual Allowance Budget}_{\underline{i}} - \text{Base})\underline{]}$$

In which:
"Base" equals 25 million metric tons of CO_2e.
"Annual Allowance Budget$_{\underline{i}}$" is the number of allowances associated with the budget year **i** pursuant to subarticle 6.
"t" equals the current year in the compliance period (1,2, or 3) (SEMPRA1)

Comment: In order to avoid undue restrictions on covered entities ability to meet their compliance obligation, the proposed regulation includes an exemption for covered entities from the holding limit for allowances they place in their compliance accounts up to the amount of their most recent year's verified emissions, or that covered entity's direct obligation. SCE agrees that a Holding Limit is necessary to address concerns about market participants hoarding allowances with the intent to manipulate market prices. However, covered entities also need flexibility to meet their legitimate compliance obligations. The Holding Limit for each covered entity should be proportional in size to its compliance obligation. Moreover, the Proposed Regulation's Holding Limit and exemption fail to address the needs of covered entities such as IOUs that, as a result of electricity deregulation, purchase a large portion of their customer's energy requirements through contracts with non-IOU-owned power plants. Many of these contracts require the IOU to directly provide allowances to counterparties for their compliance needs. This creates significant indirect GHG compliance obligations, where the IOU is responsible for the delivery of allowances but not directly responsible for surrendering these allowances to CARB through its own Compliance Account. SCE supports CARB's intent in creating the Holding Limit exemption, as it allows entities to accumulate compliance instruments to meet their direct obligation without violating the Holding Limit. In the case of IOUs, however, the Holding Limit exemption is based upon verified emissions of only utility-owned generation—its direct obligation—and not the emissions of the counterparties that will be passed allowances from the IOUs original allocation—its indirect obligation. Thus, the Holding Limit exemption alone does not provide a sufficient mechanism to address an IOU's full obligation associated with existing electric utility contracts, and consequently will not adequately provide some covered entities a path to compliance without exceeding their Holding Limits. Under the current Holding Limit, an electric utility may be unable to procure sufficient allowances from a quarterly auction to meet its total (direct and indirect) obligations under existing agreements.

Modify section 95920(b)(3) as follows:

Holding Limit = <u>the higher of</u>

<u>(a) the Proposed Regulation's formula of</u>
<u>0.1 * Base + 0.025 * (Annual Allowance Budget – Base) or</u>
<u>(b) 50 percent of a covered entity's allowance allocation</u>.

SCE believes its suggested holding limit formula balances two objectives. First, it maintains the proposed regulation's holding limit to address potential market manipulation concerns. Second, it allows entities that have obligations under existing contractual agreements (signed prior to the issuance of the proposed regulation) the ability to satisfy those obligations without exceeding the holding limit. In addition, CARB should clarify the limited exemption from the holding limit in section 95920(a)(4)(A) to reflect the proposed regulation's intent that the exemption apply as long as the allowances are transferred to a compliance account by the end of a calendar year.

Modify section 95920(b)(4)(A) as follows:

(4) Limited Exemption from the Holding Limit.

<u>(A) Allowances up to an amount equal to the emissions reported in a positive or qualified positive verification statement covering the previous calendar year shall not count towards a covered entity's or an opt-in covered entity's holding limit provided the covered entity or opt-in covered entity transfers those allowances to its compliance account during a single calendar year.</u> (SCE1)

Comment: SCE requests clarification on the extent to which compliance entities can bank compliance instruments for future use. CARB describes its desire to allow unlimited banking numerous times in the ISOR, and SCE strongly supports this position. However, the holding limit restricts the amount of allowances compliance entities may have in each holding account (initially, around 6 million allowances and 11 million beginning in 2015). If CARB proposes to allow for unlimited banking of allowances, SCE requests that CARB clarify that compliance entities may effectively "bank" allowances in their compliance accounts. Under this interpretation, any excess compliance instruments in a compliance account on any compliance dates (either annually or triennially) would then remain in the account for use in future periods, effectively "rolling over" to these future periods. SCE requests that CARB confirm this analysis of the proposed regulation. Otherwise, as proposed, the "unlimited" banking of allowances would be extremely limited and do little to control costs. (SCE1)

Comment: ARB draft regulations establish a limit on the amount of compliance instruments that may be held by any single or affiliated group of entities. In our experience such holding limits are difficult to effectively enforce and can actually impede the proper functioning of a cap-and-trade program, particularly in the early years of the program. In order to deliver the full benefits of the market for consumers, these draft regulations need to encourage participation not just from covered entities but also from other liquidity providers so as not to discourage legitimate participation by non-emitting investors and entrepreneurs, which would create a risk of reduced liquidity. By identifying carbon offsets as a primary tool for cost containment and placing limits on offsets usage, it is unlikely that a firm could gain such a commanding presence in the offsets market that it could manipulate prices. Should ARB be concerned with market power, it may find existing regulatory programs for trading markets have already addressed this issue. For instance, Derivatives Clearing Organizations (DCOs), as designated by the U.S. Commodity Futures Trading Commission (CFTC), establish "position limits" on traders in specific commodity markets. Under the recently passed Dodd-Frank Act, which reforms derivatives market regulation, the CFTC will likely exercise the authority to set these limits. IETA recommends California rely on the relevant DCOs or the CFTC to set appropriate holdings limits, as both have the expertise and flexibility to adjust position limits as the liquidity of the market fluctuates. (IETA1)

Comment: Portions of the proposed regulation will unnecessarily constrain the market. The advantage of a cap-and-trade program is to allow market pressures to create solutions that best fit business models and consumer behaviors. Due to the small market currently proposed, some limitations are necessary. However, care must be taken to ensure market liquidity. Of particular concern are:

- The holding limit is too low. As currently written, about 70 percent of allowances, for large compliance entities will be locked in compliance accounts. This creates an uneven playing field that favors traders over regulated entities. Compliance entities must be able to hold and trade a larger portion of their allowances to adequately manage their risk throughout the cap-and-trade program.
- CCEEB recommends that the program allow compliance entities to hold sufficient allowances to cover their obligation for the entire compliance period based on a rolling 3-year emissions obligation. This change would free up allowances for the major compliance entities and enable a much more liquid market where an entity could adequately hedge its forward risk without major complications. While there are still allowances locked in compliance accounts in some years, the increase in holding limits makes these limitations much more manageable.
- CCEEB supports the recommendation of the International Emissions Trading Association that suggest that the ARB should be guided by the SEC and existing federal entities (e.g., Derivatives Clearing Organizations as designated by the U.S. Commodity Futures) to set appropriate holdings limits, as both have the expertise and flexibility to adjust holding limits as the liquidity of the market fluctuates on markets to deal with gaming and other concerns.

- CCEEB has concerns with an annual surrender requirement as it doesn't allow facilities to freely adjust their holdings over the compliance period. The annual surrender removes the benefit of a 3-year compliance period. Recognizing that there may be concerns about default risk, the ARB should not penalize entities that are not true default risks. To address this, there should be a financial assurance test that would exempt non-risk compliance entities from a yearly surrender. This change recognizes that all compliance entities have an interest in preventing each other from defaulting.
- Business fluctuations at the end of a compliance period are anticipated. These fluctuations could adversely impact the smooth operation of the market. CCEEB recommends that vintage allowances (i.e. borrowing from current year) be allowed to be used during the true-up period. This will provide a mechanism for the end of compliance truing-up will increase market confidence. (CCEEB1, CCEEB2)

Comment: The Board should remove or significantly increase the proposed holding limit. As currently proposed, the holding limit will severely restrict the ability of companies to trade economically, which will both materially increase costs and reduce liquidity. (CCC, MAZOWITA)

Comment: It is a major concern that the current provisions of the rule on holding limits preclude major compliance entities from trading and optimizing their economic position. Under this provision, the vast majority of allowances for major compliance entities will be locked up in their compliance accounts, unable to be traded. Chevron, as a large supplier of transportation fuels with two refineries and, several oil and gas fields in the state is a major compliance entity. Using basic calculations assuming that we comply with the minimum annual surrender of 30 percent as required in the cap and trade rule, over 70 percent of our allowances are frozen and cannot be traded. This provision inhibits liquidity in the market; limits the ability of entities to trade economically; and disadvantages compliance entities vs. traders which may be an unintended outcome since the trading community may represent a more serious concern for market manipulation. We must be able to trade a larger portion of our allowances to adequately hedge our risk particularly after the first two years of the cap and trade program. Additionally, there are other scenarios such as refinery shut downs, economic slowdowns, etc. that could necessitate the trading of allowances which could be stuck in our compliance account. We propose to increase the holding account limit for compliance entities to two times the average of the previous two year’s reported emissions for compliance entities. This change would free up allowances for the major compliance entities and enable a much more liquid market where we can adequately hedge our forward risk without major complications. While there are still allowances locked in our compliance account in some years, we feel that the increase in holding limits makes these limitations much more manageable. We are proposing an increase in holding limits for compliance entities only, so traders and speculators would not be affected by this change. By increasing the compliance entity holding limits you are creating a much more liquid market where major companies with the most at stake in the cap and trade program can achieve a lower total cost of compliance, and you are reducing overall financial impact on California economy. (CHEVRON1)

Comment: WSPA understands the theoretical concept of imposing holding limits as a way to reduce or eliminate the potential for hoarding of market allowances. However, it should be clear that such limits may reduce liquidity and even inhibit efforts to achieve mandated emission reductions. As written, the proposed regulations appear to limit holdings to a fraction of the amount needed for facilities to ensure compliance. Conversations with ARB staff indicate that the intent was to allow facilities to hold allowances in amounts at least equal to past emissions plus some ability for growth or increased production. However, the language in the proposed rule is inconsistent with the stated objective. We recommend that ARB convene a working group to develop appropriate language governing proposed holding limits. (WSPA1) (WSPA2)

> **Response:** We agree that the language was unclear, and we rewrote the section on calculation of the limited exemption. We discussed the language with a number of stakeholders, and staff believes the revisions to be clear.
>
> In addition to the allowances an entity may have in its Holding account under the holding limit, covered entities may accumulate allowances in their compliance accounts up to an amount given by the limited exemption contained in section 95920(b)(4). The limited exemption increases each year to allow covered entities to accumulate for compliance.
>
> However, we agree that the language governing calculation of the limited exemption was unclear. We replaced the language on the limited exemption with new section 95920(d)(2). This text explains the date and manner in which the amount of the limited exemption increases each year. It also explains how the limited exemption is reduced following the triennial surrender. At that point, the entity is in the first year of a compliance period, yet the limited exemption will equal two years' worth of emissions. It then increases through the compliance period. Thus, at times, the limited exemption is less than the three-year average recommended in the comment, but during the year when a triennial obligation is due, the exemption will be higher than the three-year average.
>
> We do not agree with the assessment that covered entities will lose money due to the restriction preventing allowances from being removed from the compliance account. First, entities may actively trade allowances held in their holding accounts. In 2013 the holding limit is about 6 million MT, while in 2015 it increases to over 11 million MT. We are skeptical that covered entities would need the ability to sell greater numbers of allowances in response to temporary price changes.
>
> Holding limits are needed for covered entities because, absent a holding limit, any market participant would have the ability to accumulate sufficient instruments to exercise market power. We constructed the holding limit to balance the

covered entity's need to accumulate with the potential for market power. Once the covered entity has accumulated instruments to cover its compliance needs, the holding limit treats it the same as any other market participant.

L-34. Comment: Pursuant to the discussion on section 95857(d)(2)(A) which requires the Executive Officer to transfer penalty allowances to the highest-priced tier of the Allowance Price Containment Reserve Account, transferring allowances into the Price Containment Reserve Account will remove those allowances from the first market the auction and may inadvertently tighten the cap. Sections 95831 and 95857(d)(2)(A) need to be modified to correct this error.

Modify section 95831 as follows:

Section 95831(c) Accounts under the Control of the Executive Officer. The accounts administrator will create and maintain the following accounts under the control of the Executive Officer:

(1) A holding account to be known as the Allocation Holding Account into which the serial numbers of compliance instruments will be registered when the compliance instruments are created;

(2) A holding account known as the Auction Holding Account into which allowances are transferred to be sold at auction from:

(A) the Allocation Holding Account;

(B) the holding accounts of those entities for which allowances are being auctioned on consignment pursuant to 95831(b)(1)(B); and

(C) the limited use holding accounts of those entities consigning allowances to auction pursuant to subarticle 8.

<u>(D) Into which the serial numbers of allowances submitted to fulfill an entity's excess emissions obligation pursuant to section 95857(c) will be transferred.</u>

Modify section 95831(c)(4) as follows:

A holding account to be known as the Allowance Price Containment Reserve Account:

(A) Into which the serial numbers of allowances allocated by ARB for auction that remain unsold at auction will be transferred.

(B) Into which the serial numbers of allowances directly allocated to the Allowance Price Containment Reserve under subarticle 8 will be transferred.

(C) Into which the serial numbers of allowances submitted to fulfill an entity's excess emissions obligation pursuant to section 95857(c) will be transferred.

(D) From which the Executive Officer will withdraw allowances to sell to covered entities pursuant to section 95913. (SEMPRA1)

Response: Due to stakeholder concerns related to the potential "tightening" of the market due to the transfer of allowances used to fulfill an entity's "excess emissions," we modified the regulation to return three-fourths of the allowances into the auction account and not the price containment reserve.

L-35. Comment: Holding limits are best held in reserve as a tool to be deployed if actual market functioning identifies a problem for which a holding limits is the clear solution, rather than being made part of the "Day 1" market rules. (MSCG2)

Response: No response necessary.

L-36. Comment: Some of the mechanisms in the proposed regulation will serve to constrain the market liquidity of allowances. For example, CARB should relax the holding limit for allowances. Entities with large compliance obligations will seek to mitigate the uncertainty of market fluctuations by accruing a more significant fraction of their anticipated compliance obligation during the course of the compliance period. Current holding limits will overly restrict this cost control tool for large emitters. (APC)

Response: Except for the largest covered entities, the holding limit will have very little effect on the ability to accumulate allowances in advance of actual emissions. To give larger entities more flexibility, staff has revised the calculation procedure for the limited exemption from the holding limit (section 95920(d)) to allow covered entities to accumulate allowances ahead of their anticipated emissions.

L-37. Comment: BP strongly recommends the removal of holding limits on compliance entities and instead recommends the imposition of plans/rules to monitor for potential market power. Many of the regulation's market and trading rules combine to create serious issues around allowance availability, liquidity and market confidence. Holding limits should not apply to compliance entities, there should be no annual surrender obligation for most market participants, and the use of allowance vintages from the year in which allowance surrender is made should be permitted. Non-compliance entities should not be allowed to carry allowances across a compliance period. (BP)

Response: The regulation does have rules to prevent the exercise of market power in section 95921. We have also developed plans to monitor for the exercise of market power, through the creation of a Market Surveillance Committee of academic experts and contracting with an independent market monitoring service. However, we do not agree that these are sufficient to prevent the exercise of market power.

We revised the regulation to ensure that covered entities may accumulate allowances as needed, even in advance of their actual emissions. At the same time, holding limits are needed for covered entities because absent a holding limit any market participant would have the ability to accumulate sufficient instruments to exercise market power. We constructed the holding limit to balance the covered entity's need to accumulate instruments with the potential for market power. Once the covered entity has accumulated instruments to cover its compliance needs, the holding limit treats it the same as any other market participant.

The annual surrender provision was added out of concern that the three-year compliance period may result in large defaults on compliance obligations, hindering California's ability to meet the requirements of AB 32. The requirement for two partial payments of an emissions obligation would allow staff to identify potential defaults. We do not believe the requirement to be burdensome or to reduce the flexibility created by the three-year compliance period. If an entity's emissions are constant for a three-year period, then the total payment should be less than 25 percent of the entity's triennial obligation. Any prudent firm would accumulate that amount. The requirement would certainly not prevent the entity from undertaking speculative sales or timing its purchases to take advantage of market prices to minimize costs.

The restriction on the use of vintages of instruments for compliance follows a policy decision to prevent the borrowing of future vintages for current compliance. Borrowing would reduce the carbon price signal, leading to a reduction in direct emissions. Borrowing increases the risk of future noncompliance, due to both the greater current period emissions and reduced future supply. These factors could actually increase the amount of borrowing over time.

Non-covered entities are allowed to participate in the market and to bank compliance instruments across compliance periods. Preventing either of these could reduce the liquidity of the market. Financial participants in markets are generally considered to provide an essential service by ensuring that current market prices reflect available information on future price trends. We have rules in place to prevent these entities from exercising market power, including a holding limit without the limited exemption and an auction purchase limit that is much lower than the limit for covered entities (4 percent versus 15 percent.)

L-38. Comment: The draft proposes holding limits to all participants based on the overall market cap (section 95920(b)). The holding limit is roughly 5.5 MT CO_2e in the first compliance period and 11.5 MT CO_2e in the second compliance period for most obligated parties. Any regulations that dictate when a qualifying market participant must buy, sell or hold allowances (e.g. holding limits) will reduce the efficiency of the allowance market resulting in higher compliance costs and decreased ability of firms to manage risk. CARB should remove all holding limits for all qualifying market participants. (CONOCO)

> **Response:** We believe the holding limits are necessary to deal with the specific features of a cap-and-trade market. Price-responsive supply is a characteristic of most competitive markets. However, between the fixed cap and the quantitative use limit on offsets, the supply of compliance instruments is fixed. The price responsiveness of the demand for allowances, which depends on the ability to make direct emissions reductions, is not known but not expected to be very high. We have established the cap using procedures to avoid over-allocation, so there should not be a large supply of allowances above compliance needs. These factors combined create a market which cannot rapidly adjust to meet changes in demand conditions. Consequently, staff believes that any concentration of holdings in this market could be a source of market power and must be avoided.

L-39. (multiple comments)
Comment: The proposed regulation includes a holding limit that would dramatically limit the ability of large affiliated generators, such as Calpine, to utilize the important flexibility mechanisms otherwise provided, including unlimited banking of allowances and three-year compliance periods. While the Proposed Regulation would provide a limited exemption from this holding limit for allowances deposited in a covered entity's compliance account up to its most recent year's reported emissions, this would effectively nullify the flexibility afforded by limiting the annual compliance obligation to only 30 percent of the previous year's emissions. See 17 C.C.R. section 95855(b). In other words, covered entities would need to transfer 100 percent of their annual compliance obligation to their compliance accounts each year to avoid exceeding the holding limit. This would unfairly deny the largest generators within the State with the same flexibility afforded to other generators and would therefore place the largest generators at a competitive disadvantage. Further, the holding limit would severely restrict the ability of the largest generators within the State to bank allowances for use at a later time. This could forego the important early reductions to be gained by allowing unlimited banking of allowances. Although Calpine understands the importance of assuring that no one entity controls the allowance market or hoards allowances, Calpine is strongly opposed to the Proposed Regulation's holding limit, which it understands will equate to only approximately 6.02 million metric tons CO_2e for the first year of the program.

At the very least, Calpine believes that the holding limit must at least be equal to the sum of the amount derived through application of the formula appearing at subsection 95920(b)(3) (e.g., 6.02 million metric tons CO_2e during 2012), plus 70 percent of a covered entity's emissions reported during the preceding calendar year, plus all banked allowances from prior vintages. Modify section 95920 as follows:

> (A) General Prohibitions on Trading.
> (B) Holding Limit.

(1) The holding limit is the maximum number of California GHG allowances that may be held by an entity or group of associated entities registered pursuant to section 95830.

(2) The holding limit will apply to each entity with a holding account.

(3) Calculation The holding limit will be calculated and applied within each calendar year using the following formula:
Holding Limit= 0.1*Base+ 0.025*(Annual Allowance Budget - Base) + 0.7(GHG Emissions) + Banked Allowances

In which:

"Base" equals 25 million metric tons of CO_2e.

"Annual Allowance Budget" is the number of allowances associated with the current budget year pursuant to subarticle 6.

"GHG Emissions” is equivalent to the positive or qualified positive GHG emissions reported by a covered entity or group of associated entities form the previous data year.

"Banked Allowances” is all allowances from a prior vintage year held by a covered entity or group of associated entities. (CALPINE1, CALPINE2)

Comment: Section 95920(b)(3) (p. A-105) sets out the method for calculating the holding limit in each year. There does not seem to be sufficient justification in the ISOR for the manner in which the holding limit is calculated. The ISOR refers to the holding limit proposed by J. Harris in a paper prepared for the Western Climate Initiative. However, the analysis in that paper was unsatisfactory. The analysis relied heavily on controls for markets for agricultural products without explaining why agricultural products markets provide a good model for carbon markets. Additionally, there does not seem to be sufficient justification in the ISOR for the level of the holding limit that would apply to covered entities that will need to accumulate allowances to meet their compliance obligation. The holding limit under section 95920(b)(3) would be six million metric tons in 2012, declining over time as annual allowance budgets decline. Although that holding limit might be appropriate for opt-in entities under section 95813 (p. A-43) or voluntarily associated entities under section 95814 (p. A-44), it is too low for very large covered entities. Some covered entities, including one of the SCPPA members, have annual emissions that are more than twice six million metric tons per year. The holding limit would preclude such large covered entities from banking a significant portion of allowances they would need, while smaller covered entities would be allowed to bank a multiple of their annual emissions. Restricting banking by large covered entities by an overly tight holding limit would conflict with the policy establishing banking without restriction as a key cost-containment mechanism. Unlimited banking allows covered entities to manage their acquisition and accumulation of allowances to control compliance costs. Additionally, unlimited banking provides an incentive for covered entities to make early reductions by permitting the early accumulation of allowances in excess of a current compliance obligation to avoid higher future allowance prices. The tight section 95920(b)(3) limit on banking by large covered entities would reduce the efficacy of that incentive. Section 95920(b)(4) (p. A-105) provides for a "limited exemption" from the holding limit for allowances that are held in a covered entity's compliance account that would be approximately equal to the compliance obligation that the entity had accumulated during a compliance period, but for a large entity the "limited exemption" would not provide meaningful relief. A large entity that had annual emissions that were twice the holding limit would be permitted to bank less than 20 percent of its total compliance obligation for a triennial period. Prudent banking of allowances in early years of the program by covered entities should not be discouraged. The resolution that the Board will consider on December 16 should permit the staff to consider alternatives to the holding limit specified in section 95920(b)(3) as a change to the Cap and Trade Regulation that will be considered during the "15-day" revision process. The change should permit large covered entities to bank more allowances than under the currently drafted provisions. (SCPPA1)

Comment: SCPPA recommends that the holding limit for an entity should be the higher of the currently proposed limit or twice the entity's most recent annual emissions burden. The limited exemption from the holding limit should be clarified and calculation of the exemption should take into account the fact that the verification statement for each year's emissions will not be available until late the following year. Holding limit should be adjusted to accommodate large covered entities: The holding limit and the exemption would not allow a large covered entity to bank many allowances beyond its compliance obligation. This is too restrictive, given that banking is an important market stabilization and cost containment measure. To give large covered entities more flexibility and to retain the flexibility already afforded to smaller entities, the holding limit for each entity should be set at the higher of: the amount calculated using the formula in section 95920(b)(3); or twice the sum of the emissions reported in the entity's most recent set of verified emissions reports. (Note that a utility may have more than one emissions report and verification statement, as each generating facility and imported electricity must be reported and verified separately.). Market participants that are not covered entities, such as voluntarily associated entities, will not have an emissions burden, so the applicable holding limit will be the amount calculated using the existing formula in section 95920(b)(3) (the "Base Limit" in the wording proposed below). Modify section 95920(b)(3) as follows:

> (b)(3) *Holding limit =* <u>The Base Limit or the Emissions Burden Limit, whichever is higher</u> ~~0.1*Base + 0.025*(Annual Allowance Budget– Base)~~

In which:

"<u>Base Limit" = 0.1*Base + 0.025*(Annual Allowance Budget – Base)</u>

“Base” equals 25 million metric tons of CO_2e.

“Annual Allowance Budget” is the number of allowances associated with the current budget year pursuant to subarticle 6.

“Emissions Burden Limit” means twice the sum of the entity’s verified emissions in the most recent year for which verification statements have been submitted. (SCPPA3)\

Comment: The limits on holding of compliance instruments should be removed. If holding limits are established they should be set at a level that is greater than an entity’s annual emission obligation. Section 95920(b) limits the number of allowances a regulated entity can hold in any given year. There are already existing laws to prohibit unfair competition. Further, other provisions of the regulation, including participation by non-covered entities, disclosure of auction and transaction information, periodic distribution of allowances, including through an auction mechanism, and annual surrender of allowances will together prevent hoarding of compliance instruments. For this reason, WPTF opposes establishment of holding limits. Neither the EU ETS nor RGGI have established holding limits on market participants and to our knowledge market manipulation problems have not arisen in those programs. We therefore recommend that holding limits be eliminated. If holding limits are applied, they must be set at a level that enables larger participants to manage their compliance during a compliance interval and for future compliance intervals. As currently formulated, the holding limit would severely restrict the compliance flexibility for large entities, because it could prevent holding of an amount of allowances in active holding accounts greater than 70 percent of the previous year’s emissions (since 30 percent of allowances must be retired annually). Instead, the PRO should tie each entity’s holding limit to the level of the previous year emissions and at a percentage greater than 100 percent. (WPTF)

Response: We agree with the concern that the existing language on the holding limit and limited exemption does not clearly indicate that the covered entities will have the capacity to accumulate allowances to meet their obligation, including some ability to accumulate in advance of their actual emissions. Staff revised the text and added completely new language covering the limited exemption from the holding limit that is available to covered entities (section 95920(d).) Staff believes the new text clearly explains how the limited exemption is calculated and provides covered entities with sufficient flexibility to minimize their costs of meeting their obligations.

We believe that changes made to the regulation render incorrect the calculations offered in the comments. For example, in the first compliance period, entities may hold around 6 million MT of allowances in their holding account. Since the first compliance period now consists of only 2013 and 2014, an entity emitting 12 million MT per year could keep 25 percent of its first-period compliance obligation in its holding account. It does not have to transfer 100 percent to its compliance account, as the comments assert. In the second period, the holding limit is about 11.5 million MT, so an entity emitting 12 million MT per year could keep about one-third of its triennial obligation in its holding account. Staff believes this is sufficient for the entity to take advantage of the flexibility of three-year compliance periods while balancing flexibility against the need to limit the exercise of market power. The entity would retain sufficient flexibility to time purchases or sales of allowances based on changes in market prices, and thus would not be at a competitive disadvantage compared with smaller emitters. Therefore, staff sees no reason to implement the change to the holding limit proposed in the comments.

We disagree with two assertions made by WPTF. First, provisions of the regulation other than the holding limit do not prevent entities from accumulating sufficient allowances to create market power. Those rules do promote greater knowledge among market participants of who is accumulating allowances, and staff does expect that this will help market participants respond to the threat of market power. Second, both RGGI and the EU ETS have a more price-responsive supply of instruments than does the California program, stemming from greater use of offsets and the creation of supply of allowances under their respective caps that creates a large cushion at the beginning of their programs.

L-40. Comment: Section 95914(f)(1) (p. A-101) states that the total number of compliance instruments held by a group of entities with a corporate association must be less than the holding limit. However, section 95920(b)(1) (p. A-105) provides that the holding limit applies to California GHG allowances rather than to compliance instruments, which includes offsets. Section 95914(f)(1) should be revised to be consistent with section 95920(b)(1) so that it applies to the total number of allowances rather than compliance instruments that are held by a group of entities with a corporate association, thereby precluding the limit from applying to offsets. Section 95914(f)(1) should also be clarified to provide that the holding limit does not apply to allowances in limited use holding accounts and to provide that the section 95920(b)(4) (p.A-105) “limited exemption” for allowances that are in an entity’s compliance account applies to each entity in the group. If the holding limit stays the same regardless of the number of entities in the group or the size of their compliance obligations, this should be made clear by deleting the reference to the holding limit “of the group of associated entities.” Having a single holding limit for all SCPPA members together, if they are not exempted from corporate associations as requested in section IX.I, would be very restrictive. A higher limit (for example based on the sum of the group members’ compliance obligations) should be considered. Modify section 95914(f)(1) as follows:

> The total number of ~~compliance instruments~~<u>California GHG Allowances</u> held <u>in holding accounts and compliance accounts (subject to each entity’s holding limit exemption)</u> by a group of entities with a disclosable corporate association must sum to less than the holding limit ~~of the group of associated entities~~ pursuant to section 59520(b). (SCPPA1)

Response: We agree with the need to correct the reference to compliance instruments as part of the calculation of the holding limit, which was originally part of section 95914(f). We made the correction, which is now part of section 95920(a). We agree with the need to exempt allowances in limited-use holding accounts from the holding limit. This correction is now section 95920(b)(2).

We disagree with the comment that clarification is needed that the limited exemption applies to the facility not a corporate association. Entities qualify for the exemption when they transfer allowances into their compliance account. Then the allowances can only be used for that entity's compliance, so there is no way they can be construed as belonging to the corporate association. The holding limit, which applies to allowances in holding accounts, is shared across members of the association.

We revised the criteria in section 95834 governing when entities have a direct or indirect corporate association, which would trigger a joint application of the holding limit to members of the association. We understand that the entities referred to in the comment would not be part of an association under the new criteria. Therefore, we do not see a need for the revision to the holding limit calculation recommended in the comment.

L-41. Comment: Section 95920(b)(2) (p. A-105) states that the holding limit will apply to each entity with a holding account. It is unclear from this provision whether the holding limit will be applied across all types of accounts (holding, compliance, and limited use holding accounts), or just holding accounts. Mr. R. Olsson, in a teleconference with SCPPA members on November 19, 2010, stated that the holding limit is intended to apply to allowances held in holding accounts and compliance accounts (subject to the "limited exemption" under section 95920(b)(4) (p. A-105) for allowances held in compliance account), but that the holding limit is not intended to apply to limited use holding accounts. For clarity, modify section 95920(b)(2) as follows:

The holding limit will apply to <u>the California GHG allowances in</u> each entity<u>'s</u> ~~with a~~ holding account <u>and compliance account (subject to the Limited Exemption in section 95920(b)(4))</u>. (SCPPA1)

Response: We agree with the need to exempt limited use holding accounts from the holding limit calculation, and the corrected text is new section 95920(b)(2).

L-42. Comment: The holding limit should only apply to California GHG allowances, or MJRPs should be exempted from the holding limit requirements. The proposed regulation provides that the holding limit applies to "compliance instruments," which includes offsets. If the holding limit were to apply to both California allowances as well as allowances from other jurisdictions, this restriction could be especially problematic for an MJRP operating in multiple linked jurisdictions. PacifiCorp therefore urges ARB to amend the proposed regulation to apply the holding limit to only California allowances, such that a regulated entity could exceed the holding limit as long as its California allowances did not exceed the holding limit. Alternatively, PacifiCorp requests a limited exemption from the holding limit for MJRPs to ensure they can acquire sufficient allowances to meet their compliance obligations in all of the jurisdictions within which the MJRP operates. (PACIFICOR1)

Response: We agree with the need to correct the reference to compliance instruments as part of the calculation of the holding limit, which was originally part of section 95914(f). Staff made the correction, which is now part of section 95920(a).

If California links to other jurisdictions or other cap-and-trade programs, there will be another regulation that creates the link. That linking regulation will address the calculation of the holding limits for the linked programs.

L-43. Comment: Limited exemption from holding limit needs clarification. Section 95920(b)(4) sets out the limited exemption from the holding limit for allowances held in a covered entity's compliance account. This exemption should be retained, as it is crucial to allow for the accumulation of allowances for surrender at the end of the compliance period. However, the drafting of the exemption provision should be clarified. According to section 95920(b)(4)(B) as written, in 2014 the holding limit exemption for an entity would be that entity's 2011 emissions plus its 2012 emissions plus its 2013 emissions. Emissions from 2011are included in each year, given the language in sections 95920(b)(4)(A) and (C). The first compliance period's emissions are deducted from the exemption at the end of 2015 and the second compliance period's emissions are deducted at the end of 2018, as apparently required by section 95920(b)(4)(C). SCPPA seeks staff confirmation that the limited exemption is intended to operate this way. The calculation of the exemption should take into account the fact that the verification statement for each year's emissions will not be available until late the following year. Under section 95920(b)(4)(A), the exemption is based on emissions reported in a verification statement covering the previous calendar year. This is problematic because an electric power entity's verification statement for a year is not due until October 1 of the following year. How will the exemption be calculated prior to that date? Furthermore, section 95920(b)(4) as currently drafted assumes that there will be only one verification statement per entity, but an entity may have more than one verification statement each year, if it operates more than one facility. The clearest and simplest way to draft the limited exemption provision may be to state how the exemption is calculated for each year 2012 through 2020, year by year, rather than using general provisions. (SCPPA3)

Response: We agree with the concern that the existing language on the holding limit and limited exemption does not clearly indicate that the covered entities will have the capacity to accumulate allowances to meet their obligation, including some ability to accumulate in advance of their actual emissions. We revised the text and added completely new language covering the limited exemption from the holding limit that is available to covered entities (section 95920(d).) We believe the new text clearly explains how the limited exemption is calculated and provides covered entities with sufficient flexibility to minimize their costs of meeting their obligations.

L-44. Comment: PG&E supports a holding limit for unregulated entities. However, PG&E believes a holding limit is not necessary for regulated utilities. Utilities do not have any incentives to boost allowance prices because they have cost-based rates for service. In addition, utilities face various requirements to hedge against volatile commodity prices, which are likely to conflict with the holding limit. PG&E, by virtue of its electricity and natural gas services, has a greater need for allowances than perhaps any other single entity. A one-size-fits-all holding limit, if designed to accommodate PG&E's need, could be quite high. With that in mind, PG&E believes an exemption for regulated utilities is an appropriate policy choice. Although PG&E has offered specific language, PG&E is open to alternatives for setting the holding limit and counting toward it in a way that enables a regulated utility to implement an orderly and gradual purchase of allowances over time and to effectively manage the volatility in allowance prices. Modify section 95920(b)(2) as follows:

(b)(2) <u>No holding limit shall be applied to the holdings of a publicly owned utility operating under a plan approved by the governing board of the utility. No holding limit shall be applied to the holdings of an investor-owned utility operating under a plan approved by the California Public Utilities Commission.</u> (PGE1)

Response: We disagree with the comment, since the holding limit and limited exemption are large enough for the utilities to meet their direct emissions obligations. In addition, we modified the regulation to exempt the allowances utilities hold in limited-use holding accounts from inclusion in the holding limit calculation. Utilities have also asked for latitude under the holding limit to accumulate emission allowances for eventual transfer to generators with whom they have long-term contracts. However, we believe that the rules governing beneficial holdings added to new section 95834 are sufficient to handle these instances without revising the holding limit.

L-45. Comment: The holding limit conflicts with the cost containment unlimited banking provision and should better accommodate the needs of electric distribution utilities. The draft regulation currently proposes a holding limit formula that equals a fixed six MMT limitation on the holding of emission allowances by any entity or group of associated entities. It also includes a limited exemption for allowances that are transferred into an entity's compliance account equivalent to its annual emissions accumulating annually over the compliance period. The holding limit provision runs contrary to the overall cost containment strategy of "unlimited" banking of emission allowances. The currently proposed holding limit may work well for small covered entities but is unnecessarily restrictive for larger entities. If a holding limit is applied to electric distribution utilities the LADWP recommends that the limited exemption be retained for allowances placed in the compliance account. Additionally the electric distribution utility should be given the option of either the six million metric ton holding limit or a holding limit equivalent to no less than an entity's previous two years reported emissions associated with serving retail electric load. This would provide electric distribution utilities with much needed flexibility to purchase and bank allowances as needed at auction while also providing closer alignment to a large electric distribution utility's actual compliance obligation. Additionally the "group of associated entities" should exclude electric distribution utilities in so far as many electric distribution companies jointly own or have entitlement shares in the same electric generation facilities. (LADWP1)

> **Response:** We have used the term “unlimited” to refer to the length of time compliance instruments may be held before they are used, not to any ability to hold an unlimited number. Regarding the application of corporate association requirements to utilities, we believe that revisions to the criteria in section 95833 should prevent the utilities referred to in the comment from being subject to joint holding limits. We believe the holding limit is adequate to allow utilities to meet their direct emissions obligations. Utilities have also asked for latitude under the holding limit to accumulate for eventual transfer to generators with whom they have long-term contracts. However, we believe that the rules governing beneficial holdings added to new section 95834 are sufficient to handle these instances without revising the holding limit.

L-46. (multiple comments)
Comment: The Executive Officer's authority to limit or prohibit transfers from holding accounts should be modified. Section 95831 sets up account types for the cap and trade structure, and includes language in (b)(2)(B) that indicates that the holding account of any entity may be restricted by the Executive Officer to limit or prohibit transfers in and out of the holding account. SMUD would appreciate some clarification here of how or when the Executive Officer may act to limit an entity’s holding account. Presumably, such action should only be taken for cause, but there are no causes or problems cited in the regulation that would act to trigger the Executive Officer’s authority in this regard. Failure to indicate when the Executive Office may so act adds to risk for market participants. (SMUD1)

Comment: Section 95831(b)(2) (p. A-50) provides that the Executive Officer may impose various restrictions on an entity’s holding account. Such restrictions may have negative effects on the ability of the entity to meet its compliance obligation and may cause the entity to default under contracts for allowance transactions with third parties. While it may be appropriate for the Executive Officer to have the power to impose such restrictions, the Executive Officer should only be able to exercise that power in specific circumstances, for example, when the entity has committed an offense or the Executive Officer believes on reasonable grounds that the entity is about to commit an offense. Section 95831(b)(2) should specify these circumstances. Furthermore, in the interest of procedural fairness, the Executive Officer should be required to notify the entity of the intended restrictions, their expected duration, and the reasons for imposing them, before any restrictions are placed on the entity’s account. Lastly, sections 95920(c) (p. A-106-107) and 96011 (p. A-179-180) as well as section 95831(b)(2) allow the Executive Officer to impose restrictions on an entity’s holding account. Sections

95831(b), 95920(c), and 96011 should be coordinated with cross-references and perhaps even combined. (SCPPA1)

> **Response:** We agree with the need to consolidate multiple references to account restrictions, and modified section 95831. In addition, the original sections 95831(b) and 95920(c) were moved to new section 95921(f), to consolidate the text which deals with account restrictions that may be imposed for rule violations.
>
> Section 95921(f) makes clear that the restrictions would be imposed for rule violations. We see no need to add the notification procedure suggested by the comment because ARB's existing enforcement process already involves notification prior to resolution of violations.
>
> Section 96011 was kept separate to make clear the authority of the Executive Officer.

L-47. Comment: Regarding Specific Account Designation for Disposition of Allocated Allowances, modify section 95870 (c)(1) as follows:

> The Executive Officer will place an annual individual allocation in the <u>limited use</u> holding account or <u>compliance account, as appropriate</u>, of each eligible distribution utility on or before January 15 of each calendar year from 2012-2020 pursuant to section 95892. (NCPA1)

> **Response:** We agree with the approach behind the suggested language. However, the language was added to section 95892(b), which contains the details of the transfers to utility accounts. This section also explains how transfers to a Joint Power Agency account would be handled.
>
> Original section 95870(c) was modified and moved to section 95870(d). New section 95870(c) was added to include new language as directed in Resolution 10-42 to specify how many allowances will be set aside for Voluntary Renewable Electricity reductions.

L-48. (multiple comments)
Comment: ARB needs to clarify the provisions governing holdings for associated companies. It is unclear how the regulations on individual companies may affect joint ventures or other corporate entities. In addition some facilities must be able to hold allowances for up to three years due to the nature of their manufacturing or industrial processes. We recommend that ARB convene a working group to develop appropriate language governing holdings. (WSPA1, WSPA2)

Comment: The proposed regulation would place a holding limit on the number of allowances that can be held by any one entity (section 95920). These limits have implications for entities with complex ownership interests, such as joint powers agencies (JPAs) under section 95914, which requires the disclosure of direct and indirect

"Corporate Associations." For purposes of holding allowances for program compliance, the proposed regulation should clarify that the holdings of a JPA are not counted when calculating the holding limit of any of its individual members, and likewise, allowances held by any of the individual members of a JPA shall not be included in calculating the holding limit of the JPA. As with all aspects of auction design, the implementation of the holding limit must be narrowly tailored as not to limit the ability of Covered Entities to cost-effectively manage their compliance burden. (NCPA1)

Comment: SCPPA is a joint powers agency, constituted in accordance with sections 6500-6536 of the California Government Code. The consequences of having a corporate association with other entities are significant. Under sections 95914(e) and (f) (pp. A-100-102), the purchase and holding limits would be applied to all entities with corporate associations with each other as if that group were one entity with no increase in the limits to reflect the size of the group. This may be problematic for SCPPA members, as some members will have high compliance obligations. For example, if the SCPPA members do not take advantage of the section 95892(b)(2) (p. A-83) option to have the Executive Director place their allocated allowances in their compliance accounts and, as a result, have to buy allowances through the auction, they could need to buy more than ten percent of the allowances offered in a given auction, exceeding the section 95911(c)(2) (p. A-88) purchase limit (assuming that section 95911(c)(2) is not revised to exempt POUs as well as IOUs from the purchase limit as SCPPA recommended in the previous comment. The section 95920(b)(3) (p. A-105) holding limit of six million metric tons in 2012 and declining thereafter could also be a problem for SCPPA members, given that one member alone has annual emissions that are more than twice that level. Given the particular circumstances of POUs, with their high compliance burdens and close regulation by their governing boards, groupings of POUs in Joint Powers Agencies should be excluded from being "corporate associations" under section 95914(a). This can be achieved by adding a new section 95914(a)(1)(3) as follows:

(1) <u>Membership of a joint powers agency established in accordance with sections 6500-6536 of the California Government Code will not constitute a direct or indirect corporate association between members of the same joint powers agency.</u> (SCPPA1)

Response: We agree with the need for clarification and made significant changes to section 95833. First, the level of control that would result in a group of entities being declared a corporate association is raised from 20 percent to 50 percent. This ensures that we only capture instances where one entity controls another. For an entity with a level of control over another entity of between 20 and 50 percent, staff created a requirement to disclose the relationship as an aid to market monitoring. Second, we added an exemption from the corporate association rules for entities that are affiliated but are subject to state or federal affiliate compliance rules. This text was added as new section 95833(a)(4), to cover entities where there is a level of control but government regulations prevent joint market activities. These changes should ensure that the issue raised in the comment does not occur.

L-49. (multiple comments)
Comment: In order to incentivize innovation, CLFP urges CARB to ensure that credits be transferrable between facilities owned by the same entity. Transferable credits will succeed in giving producers the incentive to increase innovation across facility portfolios, especially where such upgrades make the most sense for the business. For instance, it may fit into a company's overall procurement strategy to upgrade a system at a plant that emits less than 25,000 tons CO_2e per year rather than at one which must buy allocations. The reward for those reductions should be reflected in the company's overall participation in the cap and trade program. (CALFP1)

Comment: CLFP recommends allowing the transfer of compliance instruments/credits between facilities owned by the same entity thereby providing incentives to food processors to increase innovation across facility portfolios. (CALFP1)

> **Response:** Under existing rules, compliance instruments held in holding accounts may be transferred between holding accounts of facilities owned by the same entity. If one facility could reduce its emissions, it could transfer the instruments from its holding account to any other facility.

L-50. Comment: Section 95831(a)(4)(B) (p. A-49) provides that a covered entity may not remove compliance instruments from its compliance account. This may be problematic for SCPPA members. SCPPA members are publicly-owned utilities ("POUs") that will receive an administrative allocation of allowances that will be deposited at their election into their compliance accounts under section 95892 (p. A-83). Several SCPPA members (Anaheim, Burbank, Cerritos, Colton, Glendale, Pasadena) participate in a generating station, the Magnolia Power Project ("Magnolia"), which is operated by a SCPPA member, Burbank, and owned by SCPPA. The operator may have the compliance obligation, but the allocation of allowances will be to the SCPPA members. There needs to be an exemption from section 95831(a)(4)(B) to allow the SCPPA participants in Magnolia to transfer allowances from their compliance accounts to the compliance account of the plant operator. In addition, there needs to be a provision in the regulation that would allow the operator of Magnolia, Burbank, to establish a separate compliance account for these allowances to avoid commingling of Magnolia allowances with the allowances that Burbank will hold to cover its own compliance obligation. (SCPPA1)

> **Response:** We agree with the comment and revised section 95892 to address the problem. Section 95892(b)(2) allows utilities receiving an allocation to inform the Executive Officer whether to transfer the allowances to the utility's compliance account, or that of a JPA, a generator operated by a POU, or an electrical cooperative. The approach recommended in the comment is therefore not needed.

Staff also added a new definition "Joint Powers Agency(ies)" to section 95802(138), and modified section 95892(b)(2)(A) to include POUs in Joint Powers Agency(ies). We also deleted section 95914 as previously written, and added a new section 95814(e)(2).

L-51. Comment: Option for publicly-owned utilities to direct allowances to either auction by consignment or simple compliance provides flexibility but carries risk. Section 95982 (b)(2) states that publicly-owned electric distribution utilities must inform the Executive Officer at least 90 days prior to receiving annual allowances what portion of the allowances should be placed in the utility's compliance account to be used only for compliance, and the utility's limited use holding account to be consigned for auction. While SMUD appreciates the flexibility provided to publicly-owned utilities to choose to apply their allowance allocation to compliance without the price risk inherent in allowance auctions, we see other risks in this approach that we believe ARB should carefully weigh prior to adoption. These risks include the possibility that reduced auction participation by some public entities will increase allowance prices and price volatility because of reduced participation.

In addition, since the provisions of 95982(d) would no longer apply to allowance value that is reflected in the allowances placed in an entity's compliance account, there is the potential for reduced revenues dedicated to AB 32 purposes. This may serve to increase allowance prices in the long run if such reduction in specifically dedicated revenues leads to fewer investments in energy efficiency and renewables. (SMUD1)

Response: Section 95892 was strengthened to require electrical distribution utilities to use allowance value (not simply auction revenue) for the benefit of ratepayers, consistent with the goals of AB 32. ARB explains why all utilities should not be required to consign their allowances for auction based on the discussion starting on page II-30 and the rationale starting on page IX-61 of the Staff Report.

We do not agree with the implication that a direct allocation will lead to higher and more volatile auction prices. Several POU representatives have indicated that they would pursue a buy-as-you-go approach to the auction, in which they purchase allowances at auction as close in time as possible to when they incur an obligation. To implement this strategy, POUs would bid high for the number of allowances they need. For this reason staff does not believe that the POUs will be setting the auction settlement price. That will instead be done by entities following more speculative purchase strategies. These would be entities that are willing to run the risk of not acquiring allowances at an auction in order to maximize profits.

If utilities must consign the allowances, the utilities would have to use ratepayer funds to purchase them back at auction for compliance or for transfer to a JPA. The net effect of this, together with the small share of the sector in overall compliance, suggests that the magnitude of the effect suggested by the comment would be small.

L-52. Comment: SCE believes the Holding Limit placed on all parties in the cap and trade market is too low for IOUs. While CARB provides an exemption for direct compliance burdens, SCE will likely need to acquire allowances to fulfill its indirect compliance burdens on behalf of independent power producers in accordance with its contractual obligations.

Response: ARB has provided a mechanism through new section 95834 to allow utilities to hold allowances in excess of the holding limit for eventual transfer to generators with whom they have contracts. In addition, the utilities have the ability to acquire allowances and hold them in their holding accounts for eventual transfer to their contract counterparties. ARB believes the two provisions give utilities sufficient flexibility.

L-53. Comment: Section 95857(c), Recovery of the Untimely Surrender Obligation, states the obligation to surrender allowances for excess emissions is immediately due and upon determining that a covered entity has excess emissions, the Executive Officer is allowed to prevent any transfers of compliance instruments from an entity's holding account to transfer any and all allowances from the holding account to its compliance account until the retirement obligations of this section are met. It is not appropriate to allow the Executive Officer to restrict an entity's holding account if ARB alleges an entity is determined to be in violation of provisions of this article. This provision circumvents dispute resolution procedures and allows the ARB substantial opportunity to force reconciliation of an enforcement matter when an entity disagrees that there is non-compliance. For example in the situation where there is a dispute that insufficient allowances were retired ARB could "restrict" the entity's allowance account, potentially causing additional future noncompliance because the account cannot be accessed. This section would prevent the company alleged to be out of compliance from transferring any allowances from their account until the excess emissions "penalty" is reconciled. If a dispute is under consideration among the entities at the time of the next compliance deadline, the entity would basically be forced into noncompliance again because it would not be able to transfer allowances from its account to meet the new compliance obligation. Modify Section 95857(c) as follows:

(c) Recovery of the Untimely Surrender Obligation.

(1) The obligation to surrender allowances for excess emissions is immediately due;

~~(2) Immediately upon determining that a covered entity has excess emissions, the Executive Officer shall prevent any transfers of compliance instruments from the holding account controlled by the covered entity;~~

~~(3) The Executive Officer shall transfer any remaining allowances from the Holding Account controlled by the covered entity with excess emissions to its compliance account until the retirement obligations of this section are met;~~

(2)~~(4) If the Executive Officer is unable to retrieve sufficient allowances using the above process,~~ the Executive Officer shall provide the deficient covered entity 30 days to secure the allowances needed to cover its untimely surrender obligation;
~~(5) If the covered entity fails to transfer allowances equal to the untimely surrender obligation pursuant to this section to its compliance account within the period specified in 95857(c)(4), the Executive Officer will:~~

~~(A) Identify holding accounts controlled by affiliates of the deficient covered entity to which the covered entity has transferred compliance instruments during the compliance period for which a compliance obligation remains unfilled; and~~

~~(B) The Executive Officer will prevent transfers from the holding accounts identified in (A) above, and retrieve allowances from those accounts to meet the untimely surrender obligation pursuant to this section.~~

(3)~~(6)~~ Additionally, if the covered entity or opt-in covered entity does not surrender sufficient allowances equal to its untimely surrender obligation pursuant to this section by the end of the 30-day period, the Executive Officer may pursue enforcement activities pursuant to subarticle 15. (SEMPRA1)

Response: The comment is now moot as we have replaced the section of interest. The section became unnecessary with the addition of a new section 95857(c), which created a new method of dealing with failure to meet the untimely surrender obligation with a new untimely surrender obligation. We believe the new procedure will be more effective and less cumbersome in securing compliance than the original system.

M. OFFSETS

This section includes responses for comments concerning the offsets provisions of the regulation, including sections 95970–95988 and sections 95990–95997. Major topics include limits on the geographic location of offset projects; limits on the use of offset credits; quality of offset credits; linkage with other offset and carbon trading programs; offset project registries; monitoring, reporting, and record retention requirements; verification; recognition of early action; and sector-based crediting.

Limits on Offsets

Restrict Offsets to Local and/or In-State Offset Projects

M-1. (multiple comments)
Comment: Polluting facilities should reduce their carbon emissions in the communities where they pollute, rather than be allowed to pay for offsets far from home. (FORMLETTER07)

Comment: Agricultural offset credits should come from California. Agricultural practices that reduce GHG emissions can provide multiple environmental and health benefits, including improved air and water quality and enhanced wildlife habitat. Offset credits should be limited to California to realize the co-benefits of these activities. (CACAN1)

Comment: We believe that the use of offsets should be geographically confined to within the state and possibly within the air basin where they originate. (FRESNOMINISTRY)

Comment: Although offsets may be good from a global perspective, they don't always make sense from a local community's perspective. Offsets should remain local. For instance, we can look at a place like Modesto, one of the ten most air polluted cities in America according to the American Lung Association. What if a Modesto power plant which violated air quality rules more than any other plant in the northern San Joaquin Valley for ten years and kept refusing to pay its fines had been given offsets to plant trees in Ohio. Then, the people living around that plant, 50 percent Latino, and 35 percent living beneath the poverty line would still be sick. (CATHCHAR2)

Comment: The number of offsets allowed should be geographically confined to within the State to ensure maximum reductions in California as required by AB 32 and limited to ensure the cap is not meaningless. (CVAQC)

> **Response:** The program imposes a limit on the amount of offsets that an individual covered entity can use for compliance. All offsets used for compliance are real reductions, albeit outside the cap. Allowing a limited number of offsets into the program provides cost-containment benefits and ensures that some GHG emissions reductions occur within the sectors covered by the cap-and-trade

program. The program includes provisions that would allow a maximum of 201 $MMTCO_2e$ of offsets through the year 2020. This limit will be enforced through a limit on the use of offsets by an individual entity equal to eight percent of its compliance obligation. Combined with the Allowance Price Containment Reserve, this limit ensures that a majority of reductions from the program come from sources covered by the program at expected allowance prices, while use of the reserve will relax that constraint if prices rise.

In addition, achieving the goal of climate stabilization will require a commitment to work at the international level to reduce GHG emissions globally. Although we encourage offset projects to be developed in California, we recognize out-of-state projects will expand the scope of the program to allow for more low-cost GHG reduction possibilities to be incorporated and reduce the overall costs of the program. Therefore, at this time, ARB will issue offset credits for projects located in the U.S., U.S. territories, Canada, and Mexico.

M-2. Comment: With regard to the proposed regulation's framework for accepting sector-based offset credits from developing countries, the undersigned companies respectfully urge the California Air Resources Board to give preference to offset credits that can be produced through qualified activities within the borders of the State of California. (BODEGRAVEL)

Response: While the regulation provides a framework for the potential acceptance of REDD credits, we do not currently have provisions in the regulation to approve those credits or allow them to be used in the compliance program. When it is appropriate for us to begin to consider a REDD regulatory program, we will be analyzing each of these issues very carefully. This would occur after the Board adopts the cap-and-trade regulation, and it would require a separate regulation that includes its own public stakeholder review and a separate regulatory and environmental review process.

In addition, achieving the goal of climate stabilization will require a commitment to work at the international level to reduce GHG emissions globally. Although we encourage offset projects to be developed in California, we recognize out-of-state projects will expand the scope of the program to allow for more low-cost GHG reduction possibilities to be incorporated and reduce the overall costs of the program. Therefore, at this time, ARB will issue offset credits for projects located in the U.S., U.S. territories, Canada, and Mexico if we have developed protocols that apply in each region.

No Offsets/Reduce Number of Offsets

M-3. (multiple comments)
Comment: Reduce the percentage of emission reductions allowed to come from offsets. (LISH)

Comment: I strongly object to the proposal to adopt market-based compliance mechanisms to meet a cap on GHG emissions. I oppose the use of offsets to comply. (MASCARENHAS)

Comment: We, along with dozens of environmental, public health, faith-based, environmental justice, and other organizations, continue to believe that the cap and trade program should require the vast majority of the emission reductions to occur in the state's heavily-polluting sectors that are regulated by the program. An over-reliance on offsets delays investment in transforming these sectors and denies California residents valuable co-benefits that come along with local emission reductions. (UCS1, LUDLOW, WALTERS)

Comment: ARB should severely limit the use of offsets in the Cap and Trade program. As the proposal now stands, polluting industries would be allowed to offset up to eight percent of their compliance obligations, which is almost 100 percent of their required emissions reductions. An oil refinery, utility, or other polluting company could find it more convenient and cost-effective to buy offsets far from the communities in which they pollute. Offsets do nothing to reduce the co-pollutants already harming the communities in which these large polluters operate. (CATHCHAR1, CIPAL)

Comment: "The proposed program includes provisions that would allow a maximum of 232 $MMTCO_2e$ of offsets through the year 2020. This limit will be enforced through a limit on the use of offsets by an individual entity equal to eight percent of its compliance obligation." This is double the initially proposed limit of four percent. The problems with offsets identified above, combined with the low ambition in the overall target, leads us to expect that there will be very little obligation on participants to take action at source. (CTW)

Comment: Offsets should be limited to assure the integrity of the emission reductions and fulfill the letter and spirit of the law. Excessive reliance on offsets could open up loopholes that undermine the very purposes of California's AB 32 cap on emissions. Curbing global warming will require a fundamental transformation of our energy economy, a task that cannot be outsourced to other countries. Requiring California's largest polluters to reduce their own emissions will spur technological advances that can be exported to the rest of the world, bringing green jobs to the Golden State. If polluters are allowed to outsource their emission reductions to other sectors and jurisdictions, the clean-energy revolution will be delayed. The staff proposal would allow polluters to offset almost half of the emission reductions required under this rule. That amount should be significantly reduced. (We supported the 10 percent limit in AB 1404, which was passed by the Legislature but vetoed by the Governor in 2009). (SIERRACLUBCA4)

Comment: The Board is being asked to adopt a program that forgoes the economic and public health benefits from in-state reductions, favors out-of-state reductions from virtually unlimited offsets, and creates a vastly complicated and unproven mechanism that will more likely than not fail to deliver AB 32's ultimate goal of reducing GHG emissions in a thoughtful and equitable manner by 2020. Unfortunately, this challenge to ARB's implementation of AB 32 is not new to environmental justice communities. Offsets do not maximize environmental or economic benefits for California. The regulation proposes to allow entities to use offsets for up to eight percent of its compliance obligation, which is nearly 100 percent of the entities' required emissions reductions. In addition, the regulation allows offsets outside of the regulated sectors and outside of California, and possibly the United States. In no way does this structure maximize environmental or economic benefits for California as required by AB 32. This regulation is structured in such a way that an entity can comply without actually making any emissions reductions. A review of Figure E-3 in Appendix E of the Staff Report reveals that through 2016 the combined allowances and offsets would allow greater GHG emissions than the projected business as usual emissions of the covered entities without this regulation. Clearly, this does not comply with the requirements of AB 32 to achieve the maximum reductions feasible and maximize the benefits for California. Further, by allowing allowance trading and offsets out of state, ARB is allowing the new jobs that will be created by investment in green technology to be created in other states or countries, rather than in California. In this economy, squandering opportunities to create investments and jobs within California is unthinkable, irresponsible, and contrary to the mandates of AB 32. AB 32 offers the promise of a new green economy in California and requires any market-based mechanism to maximize economic benefits for California. For the Board to consider adopting this regulation with these offset provisions is irresponsible to the millions of Californians who could benefit from the investments and jobs lost to other states. (CRPE1, CRPE3)

Comment: The current maximum offsets level, eight percent, is too high. By some calculations, this amount would allow emitters to continue with business as usual emissions levels until 2017. It may be better to run a separate program for uncapped sectors which is not linked to the permits market. More information on the "supplementary reductions concept" may be found in the Cantwell-Collins CLEAR Act, available at U.S. Senator Maria Cantwell's website. (CPC1)

Comment: Lower the offset limit. (VARON)

Comment: Eliminate the eight percent cap on offsets, which will encourage the development of GHG-reducing measures and provide additional flexibility for sources to address their GHG emissions. (SMITHS)

Comment: There is too much offsetting allowed (eight percent of emissions). Offsetting is not a robust a policy for tackling climate change as cap and trade mechanisms. The use of baseline and credit programs to generate offsets has many potential weaknesses, including the difficulty in establishing additionality and accurately projecting a baseline. Offsets should only be used in cap and trade programs as a guard against high prices, such as in the event of carbon abatement projects in capped sectors proving to be more expensive or more difficult to uncover than initially projected. Access to offsets should be limited and always supplemental to action in the capped sectors. The price of offsets is generally lower than the price of the allowances created under the cap, and often the first option for firms buying their way to compliance. It is our expectation that the generous offset provisions proposed will mean that cap and trade in California will operate as a mandatory offset program for capped participants, stimulating little or no investment in abatement within capped sectors. The decision to increase the offset provision has been justified in relation to the creation of the strategic reserve of allowances. However, the creation of a reserve is not the same as tightening the cap since it does not permanently remove the permits from the program, merely places a higher price on them. The increase in the offsets provision is therefore equivalent to a significant decrease in overall effort in the traded sector. Also, the current proposals state that the placing of the permits into the reserves will be done gradually over time, whereas, the increased offset provision is in place from the start. This is clearly imbalanced. If the proposals are not to result in significantly weakened price signals, then the additional offset provisions, if introduced, should similarly be phased in over time. (SANDBAGCC)

Comment: Drastically reduce the percentage of emission reductions allowed to come from offsets and require that 100 percent of offsets be located in California (thus providing California jobs). Californians support our global warming law because we want to green our state's economy, not outsource the job of reducing emissions to other states and countries. (STEWARTJ)

Comment: Please protect the public by reducing the percentage of emission reductions allowed to come from offsets. Californians support our global warming law because we want to green our state's economy, not outsource the job of reducing emissions to other states and countries. (FORMLETTER10)

Comment: Offsets do not and will not provide real emissions reductions. They will offset the responsibility of the State and polluting industries. This will allow pollution in California to continue both in the form of CO_2 emissions and in the form of the more immediate toxic threats from refineries, incinerators, power plants and so on. This will lead to the kinds of immediate health impacts we see around the Richmond refineries, Kettleman City, West Oakland, Fresno, and other industrial impacted areas. I would recommend that offset allowances within AB 32 be kept to a minimum in order to truly encourage clean and green economic alternatives for California. (GJEP2)

Comment: A limited role for offsets may necessary in the beginning, but the ability to offset carbon pollution must be very limited or greenhouse gases will not be cut significantly. Offsets must be allowed sparingly and less allowed every year. (BEAZLIE)

Comment: We are concerned with the doubling of offsets. (EBCHR)

Comment: Any offsets allowed should be limited and narrowly targeted to benefit the impacted communities that are suffering from power plant and refinery pollution. (COHEN2)

Comment: California must lead this nation. But I urge you also not to provide loopholes for polluting industries like offset protocols. No more half measures. Let's get the caps on the books and let industry adapt. (ARNDT)

Comment: Selling the carbon credits in no way changes the excessive amount of pollution that is expended into our environment. Let's come up with a plan that will be appreciated and praised by the future generations. (ATCHER)

Comment: I do not agree with "offsets" which allow companies to continue to pollute out atmosphere. (CUNNINGHAM)

> **Response:** We did not change the limit on the use of offsets in the program. We believe that a limited use of offsets is necessary in the program to contain costs and incentivize reductions in uncapped sectors. The program imposes what we believe is an appropriate limit on the amount of offsets that an individual covered entity can use for compliance. All offsets used for compliance are real reductions, albeit outside the cap. Allowing a limited number of offsets into the program provides cost-containment benefits and ensures that some GHG emission reductions occur within the sectors covered by the cap-and-trade program. The program includes provisions that would allow a maximum of 201 $MMTCO_2e$ of offsets through the year 2020. This limit will be enforced through a limit on the use of offsets by an individual entity equal to eight percent of its compliance obligation. Combined with the Allowance Price Containment Reserve, this limit ensures that a majority of reductions from the program come from sources covered by the program at expected allowance prices, while use of the reserve will relax that constraint if prices rise.

M-4. Comment: Please consider the following suggestions made by Union of Concerned Scientists for making the CARB program even stronger as you go forward:

1. More clearly define CARB's role in offset decisions.
2. Ensure that offsets cannot be sold more than once through different registries.
3. Lower the offset limit. (CADMANS, UCS2)

> **Response:** We agree with the comment to more clearly define ARB's role in offset decisions. We deleted Offset Project Registries from the appeals process for adverse verification statements. This clarification was made to be consistent with the MRR, and reflects stakeholder comments that the appeals process should only be limited to determinations made by the Executive Officer of ARB, and that ARB should be the only one to make these determinations. In addition, we clarified that ARB makes the final determination on whether or not a registry offset credit meets all requirements of the regulation, and we added this text to the regulation.
>
> New section 95975(c)(5) of the regulation now requires that an Offset Project Operator or Authorized Project Designee disclose any offset credits issued for the same project for any other purposes in any other program. In addition, we

added new attestations to section 95981(c). Offset Project Operators and Authorized Project Designees must make these attestation(s) in order for ARB to issue offset credits. Also, if ARB finds that ARB offset credits were issued to the offset project for the same GHG reductions or GHG removal enhancements, ARB may invalidate the ARB offset credits pursuant to section 95985. This provision addresses double-counting of the GHG reductions or GHG removal enhancements in multiple programs.

We did not change the limit on the use of offsets in the program. The program imposes what we believe is an appropriate limit on the amount of offsets that an individual covered entity can use for compliance. All offsets used for compliance are real reductions, albeit outside the cap. Allowing a limited number of offsets into the program provides cost-containment benefits and ensures that some GHG emissions reductions occur within the sectors covered by the cap-and-trade program. The program includes provisions that would allow a maximum of 201 MMTCO_2e of offsets through the year 2020. This limit will be enforced through a limit on the use of offsets by an individual entity equal to eight percent of its compliance obligation. Combined with the Allowance Price Containment Reserve, this limit ensures that a majority of reductions from the program come from sources covered by the program at expected allowance prices, while use of the reserve will relax that constraint if prices rise.

M-5. Comment: We are very much opposed to the cap-and-trade program that would allow industrial polluters to purchase carbon "offset credits" instead of reducing their own greenhouse gas emissions. (REED)

Response: We disagree that the inclusion of offsets does not require capped sources to reduce emissions. The program imposes a limit on what we believe is an appropriate amount of offsets that an individual covered entity can use for compliance. All offsets used for compliance are real reductions, albeit outside the cap. Allowing a limited number of offsets into the program provides cost-containment benefits and ensures that some GHG emissions reductions occur within the sectors covered by the cap-and-trade program. The program includes provisions that would allow a maximum of 201 MMTCO_2e of offsets through the year 2020. This limit will be enforced through a limit on the use of offsets by an individual entity equal to eight percent of its compliance obligation, or total emissions. Combined with the Allowance Price Containment Reserve, this limit ensures that a majority of reductions from the program come from sources covered by the program at expected allowance prices, while use of the reserve will relax that constraint if prices rise.

Unlimited Offsets/Increase Number of Offsets

M-6. (multiple comments)
Comment: CERP strongly supports the increase in the offsets usage limit to eight percent of an entity's compliance obligation. The offsets usage limit remains, however,

a severe and unnecessary limit on the ability of offsets to provide cost containment to the California program while delivering environmentally rigorous emission reductions. CERP recommends that in the event that half of the allowances from the Allowance Price Containment Reserve have been purchased, the offset usage limit should increase to provide additional cost containment. At that point, ARB should also use revenue from the sale of allowances from the Reserve to purchase offsets to "refill" the Reserve. Such safeguards are not only reasonable, but essential to ensure that cost containment will be available when it is needed. By limiting offsets usage to approximately eight percent of entities' compliance obligations—as ARB has proposed in the draft regulations—ARB is unduly limiting the emissions reduction potential and cost containment that offsets can provide, and increasing the costs of the Cap and Trade program for California households and businesses. CERP urges ARB to increase the offsets usage limit. At the very least, the proposed regulations should provide for the reevaluation of the offsets usage limit in the future if allowance costs become high, and provide an automatic recalibration of the limit in the event that half the allowance reserve is depleted. (CERP1, CERP3)

Comment: Dow supports the addition of new provisions in the proposed rule that would increase the offset supply via an increased offset limit if a risk of depletion in the allowance reserve is detected. Inclusion and approval of mechanisms in the final rule would allow ARB an additional and potentially robust means of containing potential runaway costs while avoiding a curtailment and/or dismantling of the cap and trade program. (DOWCHEM1)

Comment: Eliminate the quantitative usage limitation for California-based offset projects, most specifically the projects using forestry, urban forestry, and urban life cycle methane capture protocols. This would promote the AB 32 goals of achieving the GHG emission reduction cost effectiveness and providing environmental benefits to California. (OFFSETSWG2)

Comment: While IETA is encouraged that ARB has significantly increased this limit from the original four percent, IETA continues to support the removal of a quantitative usage limit. IETA believes that as long as only real, permanent, and verifiable offset credits are allowed into the market, arbitrary usage limits will only prevent further reductions of greenhouse gas emissions in a cost-effective manner. (IETA1)

Comment: IETA's membership would like to stress the importance of continuing to think about higher quality of offset limits and allowing more methodologies and standards into the state of play. (IETA2)

Comment: We appreciate that CARB staff has increased the ability to use offsets from four percent up to eight percent of the compliance obligation. However, this parameter is likely too small to accommodate the needs of a growing California economy. We recommend that CARB impose no quantitative limit on qualified offsets and that CARB not impose geographic limitations. (CMTA1)

Comment: We are very disappointed that the cap and trade program will proceed with so few approved protocols for offsets. We are glad that CARB has recognized the value of offsets as both a cost-control mechanism and a way to advance the goals of emission reductions. In addition, we appreciate that CARB staff has increased the ability to use offsets from four percent up to eight percent of the compliance obligation. However, this expansion is likely still too small to accommodate the needs of a growing California economy. We recommend that ARB set no limit on the use of qualified offsets. We offer this recommendation because the stringent offset qualification rules and the need for CARB approval of any offset protocol will ensure only the best projects are approved, and the process could constrain the availability of offsets in any event. Further, since CARB has assured quality offsets through stringent offset qualification rules and third party verification, it is redundant, and unreasonably onerous for the entity holding the offset credit to be responsible for it being real, permanent, etc. It seems clear that we shouldn't impose artificial constraints on the offset market that could provide such great benefits to the state and the environment. (AB32IG)

Comment: We also recommend you consider raising the cap on offsets for those subject to leakage. (PMTPETRO2, PMTPETRO3)

Comment: CLFP supports the notion that the eight percent level be established as a floor, and that additional offsets be allowed as necessary to maintain costs of the program within acceptable limits. (CALFP1)

Comment: We believe that the most cost-effective approach to achieving the emission reduction goal of AB 32 is via a well-designed market program that includes a robust offsets program. We believe eight percent is still too restrictive and will prevent interest and investment in innovative emissions reductions projects in uncapped sectors, which is a significant missed opportunity for climate change mitigation. This limitation will result in the loss of cost-containment from the use of offsets especially in the early stages of the Cap and Trade program, when new technologies and best practices are still being developed and implemented by capped sectors. The result will be increased costs of the entire Cap and Trade system and a loss of flexibility during the transitional years post-enactment. We request that the Board review the eight percent cap in the future as potential new offset protocols come on line. Without a promise to review the eight percent cap, this may provide a strong disincentive for capital to be invested by state or private organizations to development of new offsets. (ACC1)

Comment: Inclusion of a robust offsets program is essential to cost-containment of AB 32. The eight percent limitation is too restrictive and will prevent interest and investment in innovative emissions reductions projects in uncapped sectors. Agricultural cooperatives, in particular, have a unique opportunity to participate in carbon sequestration activities of their grower-owners and utilizing those offsets as part of the compliance rules in cap and trade. Limiting the total allowance market to only 8 percent for offset projects discourages potential participation in the program from production agriculture and could prevent this unique opportunity for agricultural cooperatives. Ag Council urges the Board to review this cap in the future as potential new offset protocols come on line. Without a promise to review the 8 percent cap, this may provide a strong disincentive for capital to be invested by state or private organizations to development of new offsets. (ACC3)

Comment: We would recommend that CARB monitor the development of the offset market and prices in the allowance market, and consider increasing this cap beyond 8 percent should prices begin to rise to higher levels than may be tolerable given the prevailing state of the economy. Unlikely other cost containment strategies such as safety valves and off-ramps, offsets do have the benefit of maintaining the net environmental integrity of the cap, so long as they come from real, verified, additional and permanent reductions. Regulatory scrutiny of the offset market is welcomed and encouraged to ensure that these requirements for offset quality are met. (CLIMATEWEDGE)

Comment: The Board should amend the offset provisions by removing the limit on offset use for compliance purposes. Limiting offset use will simply increase the cost of the program unnecessarily. The regulation should use appropriate integrity criteria to assure that offsets are verified, surplus and otherwise worthy of use in the program; but should not otherwise limit offset access or use. ARB's complementary measures directly ensure appropriate California investment in strategic low carbon fuels and technologies. (CCC, MAZOWITA)

Comment: Because climate change is a global problem that requires a global solution and because California will continue to be negatively impacted if regions outside the State do not act, CARB should re-evaluate the restrictive quantitative limits on the use of offsets while hastening and widening the approval of offset protocols to ensure adequate supply. The regulation should be designed to ensure introduction to the market of the full allowed quantity of offsets. (BP)

Comment: We recommend CARB eliminate the eight percent cap on offset use for facility compliance. Section 95854 and the Initial Statement of Reasons (pg. II-5) state that only eight percent of source's compliance obligation can be satisfied with offsets. This restriction, combined with the expected use of auctions as a means to distribute the allowances, can serve to:

- Increase leakage by sources moving to less stringent regulatory regimes;
- Restrict California's ability to lead other states into participating in the cap and trade program;
- Increase compliance costs;
- Marginalize (render inconsequential) the use of offsets; and
- Reduce offset usability. (CANTORCO2E)

Comment: While it is an improvement that CARB has increased the allowable level of offsets that can be used in a compliance period, we believe that this level should be even higher, if not unlimited, at least at the beginning of the program, to spur the development of offsets and ensure allowance availability. (LASD1)

Comment: The offset limit should be increased. Allowing only eight percent of compliance requirements to be met by offsets seems too low to provide flexibility for compliance. Constellation Energy requests that the opportunity for compliance using qualified offsets be increased substantially. (CONSTELLATIONENERGY)

Comment: The amount of offsets that are allowed in the program should be higher than eight percent. (SDCHAMBER)

Comment: We appreciate that CARB has recognized the two-fold value of offsets as a cost-control mechanism and a way to further the goals of emission reductions. We further appreciate that CARB staff has increased the ability to use offsets from four percent up to eight percent of the compliance obligation. Nevertheless, this expansion is too small to realize the full value to regulated parties and to the success of the regulation itself insofar as offsets are compliance cost mitigation instruments. We agree with the AB 32 Implementation Group in their recommendation that CARB set no limit on the use of qualified offsets. (PLOTKIN)

Comment: Expand offset use from eight percent to 25 percent so that warehousing can engage in distributed energy solutions for dealing with climate change instead of expensive fuel mandates. (IWLA1, IWLA2)

Comment: Essentially all of the studies on the economics of cap and trade show that offsets are critical to minimize costs. Although ARB adjusted its limits on the use of offsets, from four percent to eight percent, this limitation is still unnecessary. (CCEEB1)

Comment: The eight percent cap on the use of offsets should be lifted. COPC welcomes CARB's lifting of the quantitative offset usage cap to eight percent from the four percent level that appeared in the prior Preliminary Draft Regulation (see section 95854). If CARB determines that some type of quantitative usage limit is necessary, then it should be set it higher than eight percent. Such a low limit will severely hinder the ability of offsets to provide the cost containment mechanism that will be necessary to manage the costs of AB 32's implementation. It also will severely discourage the investment in and development of new offset projects, thereby failing to harness a powerful tool for combating climate change. (COPC1)

Comment: Offset credits allowed for mitigating CO_2 emissions in the PDR were limited to four percent. The proposed Cap and Trade Regulation raises the allowable percentage to eight percent. Additionally, there are only four offset protocols that CARB is currently considering for approval. As the number of available allowances declines, there will be increased need to additional and creative offset projects both inside and outside California. Therefore, more flexibility needs to be built into this aspect of the Cap and Trade Regulation, as well as an expedited approval process for new offsets. (MWDSC1)

Comment: While COPC is encouraged by the recognition that offsets should play a slightly larger role in the AB 32 cap and trade program, we remain concerned by what appear to be arbitrary limits on the use of quality offsets. COPC respectfully submits that CARB's continued embrace of a quantitative usage limit is fundamentally flawed. Establishing a quantity limitation on the use of offsets does nothing to help ensure the environmental integrity of offsets. That can be addressed far more effectively by addressing it directly (i.e. by focusing on offset quality). (COPC1)

Comment: Offsets represent an important cost containment tool for many food processors and producers. CLFP continues to strongly advocate that CARB not take a restrictive approach to the use of emission offsets by Cap and Trade program participants such as limiting the number or percentage of offsets that can be used; the geographic location of offsets; or the types of offsets that would be eligible. CARB should instead focus on the quality of offsets; that they meet the requirements of being real, additional, quantifiable, verifiable, and permanent. As long as offsets meet that rigorous standard then their use by regulated entities should not be limited for compliance purposes. (CALFP1)

Comment: We recommend that CARB remove the eight percent restriction. When faced with these restrictions, potential offset buyers will choose to expand, and possibly move their operations to areas with greater offset supply (or that are not burdened with such restrictions). Rather than quantitative limits, sources should be limited to using credits that meet CARB's qualitative criteria. Any credits which meet CARB's offset protocols should be useable as offsets in any amount. (CANTORCO2E)

Comment: The quantitative usage limit should not apply to offset projects that result in direct emission reductions within California. (OFFSETSWG1)

> **Response:** We did not increase the amount of offsets allowed to be used in the program. The program imposes a limit on the amount of offsets that an individual covered entity can use for compliance. All offsets used for compliance are real reductions, albeit outside the cap. Allowing a limited number of offsets into the program provides cost-containment benefits and ensures that some GHG emissions reductions occur within the sectors covered by the cap-and-trade program. This limit will be enforced through a limit on the use of offsets by an individual entity equal to eight percent of its compliance obligation. Combined with the Allowance Price Containment Reserve, this limit ensures that a majority of reductions from the program come from sources covered by the program at expected allowance prices, while use of the reserve will relax that constraint if prices rise.
>
> The depletion of the reserve in itself may not be an indicator of a potential market issue. Therefore, we did not make a change that would require an increase in the offset usage limit if the reserve is depleted.

M-7. Comment: ConocoPhillips supports unlimited use of high-quality offsets for compliance with any cap and trade program. Emission allowances from similarly stringent cap and trade programs should qualify for compliance within the California system. CARB should increase the percentage of high-quality offset credits covered entities may use towards compliance and should include emission allowances from international trading programs (e.g. EU ETS) as a viable alternative compliance mechanism. (CONOCO)

> **Response:** We did not increase the amount of offsets allowed to be used in the program. The program imposes a limit on the amount of offsets that an individual covered entity can use for compliance. All offsets used for compliance are real reductions, albeit outside the cap. Allowing a limited number of offsets into the program provides cost-containment benefits and ensures that some GHG emissions reductions occur within the sectors covered by the cap-and-trade program. This limit will be enforced through a limit on the use of offsets by an individual entity equal to eight percent of its compliance obligation. Combined with the Allowance Price Containment Reserve, this limit ensures that a majority of reductions from the program come from sources covered by the program at expected allowance prices, while use of the reserve will relax that constraint if prices rise.
>
> The regulation includes a framework for California to link its cap-and-trade program to other emissions trading systems of similar scope and rigor. Linkage can expand the coverage of the cap-and-trade program to include emissions-reduction opportunities for sources covered in another program. The regulation does not currently include linkage to other programs, though staff anticipates bringing recommendations to the Board in 2012 for possible linkage with the programs being developed by the three other WCI Partners that are currently working to implement programs: British Columbia, Quebec, and Ontario.
>
> Each program will undergo a case-by-case analysis by staff as part of a formal rulemaking process, and the Board will need to approve regulatory amendments reflecting the linkage with a particular program before it can take effect.

M-8. Comment: ATA supports ARB's decision to increase the availability of compliance offsets under the regulation. Additional compliance offsets will provide compliance alternatives for regulated entities while ensuring real environmental benefits through offset projects. (ATAA)

> **Response:** Thank you for the support.

Carry Over of Offset Limit

M-9. (multiple comments)
Comment: The restriction on carrying over unused portions of an entity's offset limit into subsequent compliance periods should be removed. (CCEEB1)

Comment: The Council urges the Air Resources Board to propose a simple method to allow the carryover of unfilled rights to use offsets. (BCFSE)

Comment: Buyers should expect to see that they have a guarantee of that credit being able to be transacted in the future. I would suggest you carry forward offset capacity. If a facility has not used its capacity one year, then they should be able to use that in the subsequent years and bank it. (MARGOLIS)

Comment: We recommend CARB provide for the ability to carry forward/bank unused annual offset capacity. Should CARB insist on the imposition of an offset limit (whether eight percent or something greater), sources should be allowed and encouraged to bank/carry forward unused offset capacity. For example, if a source has a 100,000 ton compliance obligation it would have the ability to use 8,000 tons of offsets. If the source only uses 1,000 tons of offsets we propose that the source be allowed to carry forward 7,000 tons into the subsequent years. We also propose that the unused offset capacity be carried forward on an aggregate basis. On an annual basis, CARB should track unused, unbanked (orphaned) offset capacity from all sources. For example, in year one CARB may determine that (market wide) 100 sources used 500,000 tons fewer than would have been allowed. Under this proposal, the 500,000 ton surplus from year one would be carried forward and allocated to all sources operating in year two. The exact distribution method (and cost) can be refined at a later date. This proposal would serve to reduce compliance costs, encourage offset generation, while, at the same time, allow the State to meet its AB 32 emission reduction objectives. (CANTORCO2E)

Comment: Offsets are a crucial part of compliance entities' cost containment strategies. CARB should modify its offsets program to expand the available supply of offsets, especially in the first compliance period. SCE asks that CARB ensure that the eight percent quantitative limit on offsets is flexible over compliance periods. (SCE1)

> **Response:** The regulation requires that offsets account for eight percent of an individual entity's emissions over a three-year period. We did not allow the carryover of unused offsets within this time frame to ensure that emission reductions are being achieved by capped sources throughout the life of the program. Keeping it to the compliance period allows some flexibility by giving three years to total emissions, but still requires that emission reductions are coming from within capped sectors in all years of the program.

M-10. (multiple comments)
Comment: Dow believes that the limit on the use of offsets, set at 8 percent is too low and should be further increased. Dow is also concerned that the supply of offsets in the first compliance period will be insufficient to cover 8 percent of total retirement obligations. To address the potential shortfall in available offsets and to ensure that the program is implemented in a manner that allows this important design criteria to be achieved, Dow recommends that ARB modify the proposed regulation to allow each

covered entity to carry over any unfilled rights to use offsets. The cost implications of the rule are primarily based on the assumption that the 8 percent will be available.

To disallow access and use of an important cost containment mechanism simply because supply cannot initially match up to the demand would effectively penalize capped entities for the non-availability of a cost containment feature that under the proposed program is presumed to be fully available during the first compliance period. Allowing capped entities, in particular, EITE facilities, access to such a cost containment mechanism would help meet ARB's leakage goals, while remaining both below the eight percent offsets threshold for the program and the entity. Such a provision would also send clear signals to emission reduction project developers. (DOWCHEM1)

Comment: CERP urges ARB to allow covered entities to carry over any portion of their offsets usage quota that is unused during a compliance period. Because there may not be sufficient offset supply available in some compliance periods to meet demand, some covered entities may not be able to obtain the quantity of offsets they are allowed to use, and therefore will lose the cost containment that the offsets could have supplied. To protect the ability of offsets to provide cost containment, covered entities should be able to use additional offsets in subsequent compliance periods, up to the quantity of "unused" offsets. (CERP1)

Comments: PG&E believes that the supply of offsets in the first compliance period will be insufficient to cover eight percent of emissions, as would be permitted under the proposed regulations. To address this shortfall, PG&E recommends that each covered entity be allowed to carry over any unfilled rights to use offsets. Such carry-over could be complicated if, for example, regulators allow trading of such rights. To avoid such complexity, PG&E proposes a simple method, in which no trading of unused rights is allowed and the burden of proof is on the complying entity. For example, consider a facility X that emits 100,000 metric tons in each year. Under section 95854, facility X could cover eight percent of its emissions, or 8,000 metric tons per year, by surrendering offsets rather than allowances. If facility X uses less than its full right, it can carry over that right. For example, facility X was allowed to use 8,000 offsets, but actually covered its emissions with 97,000 metric tons of allowances and only 3,000 offsets. In the next compliance period it would be allowed to use offsets equal to eight percent of its emissions, plus 5,000 metric tons of offsets, to account for offsets that were not used in the first period. PG&E proposes that the burden of proof be placed on the complying entity. ARB can easily determine whether the burden of proof has been met because ARB will be tracking the surrender of allowances and offsets in the Retirement Account. (PGE1)

Comment: ARB proposes to enforce the eight percent limit on offset use for each three-year Compliance Period. However, depending upon conditions in offset and allowance markets, it may be uneconomic to use the full extent of offset flexibility offered in certain compliance periods. For example, if offset markets are slow to initially develop, complying entities may find it more cost-effective to rely upon emission reductions from sources under the cap, rather than offsets. However, costs might be lowered if complying entities are allowed to carry forward and even trade these "rights" to use offsets. A simple accounting mechanism that keeps track of the quantity of offsets each complying entity is allowed to use could allow them to bank and even trade these "rights" to use offsets. Such a mechanism may also lower costs by allowing firms to specialize in their use of offsets. Given the fixed administrative costs of effectively participating in offset markets, this flexibility could allow some firms to avoid these administrative costs (which could be large for smaller complying entities), while not foregoing the opportunity to achieve compliance cost savings. (ANALYSISGRP)

> **Response:** We do not agree that there will be insufficient offset supply in the first compliance period. We estimate that if every entity used their allowable eight percent offsets, approximately 26 million metric tons of offsets would be needed in the first compliance period. This reduced need is due to a start of the first compliance period in 2013 instead of 2012. At this time, based on the four offset protocols the Board has endorsed—manure digesters, forestry, urban forestry, and destruction of ozone depleting substances—ARB will be close to the supply demand for the first compliance period. We also will be looking to adopt additional Compliance Offset Protocols beginning in 2012.
>
> The regulation requires that offsets account for eight percent of an individual entity's emissions over a three-year period. We did not allow the carryover of unused offsets within this time frame to ensure that emission reductions are being achieved by capped sources throughout the life of the program. Keeping it to the compliance period allows some flexibility by giving three years to total emissions, but still requiring that emission reductions are coming from within capped sectors in all years of the program.

M-11. Comment: SCE strongly supports the use of offsets as compliance instruments for cost containment. SCE applauds CARB staff for recognizing that "a robust supply of offset credits can help to contain the costs of a Cap and Trade program" because offset credits can provide covered entities a source of low-cost emissions reductions. As SCE has noted in earlier comments, however, arbitrary quantitative limits or geographic limits on offsets will result in unnecessarily high compliance costs. The proposed regulation would only allow a maximum of 232 MMT CO_2e of offsets through the year 2020.

This limit will be enforced through a limit on the use of offsets for each covered entity equal to eight percent of its annual compliance obligation. The ISOR correctly notes that by removing 121 million allowances from underneath the cap and placing them in the Allowance Reserve, the level of stringency within the program is increased and could lead to higher allowance prices. CARB staff reasons in the ISOR, however, that this increased stringency can be addressed by allowing additional offsets in the Cap and Trade program, up to the 232 MMT CO_2e maximum. This reasoning is flawed. Although the increase in the quantitative limit on offsets from four percent to eight percent is a positive step, it does not fully counteract the pulling of allowances from under the cap to populate the allowance reserve. There is no guarantee that the four offset protocols currently proposed by CARB will provide a sufficient supply of offsets to reach the eight percent limit, particularly in the crucial first compliance period. SCE believes it is unlikely that there will be enough offsets to meet that limit.

If CARB imposes a quantitative offsets limit, SCE recommends that the limit be flexible between compliance periods to address the likelihood of a limited supply of offsets in the early years of the program. Currently, the eight percent quantitative limit is imposed on the use of offsets for each regulated entity for each compliance obligation, be it annual or triennial. In order to address concerns regarding the limited supply of offsets, especially in the early stage of the regulation, CARB should allow compliance entities to make up any shortfall of offsets in later compliance submissions. For example, in the first year of the program, if a covered entity can only purchase enough offsets in the market to fulfill five percent of its annual compliance obligation, the covered entity should be allowed to carry over the number of offsets equal to the unused additional three percent to later compliance periods. Alternatively, CARB could allow the eight percent limit to apply to a compliance entity's entire obligation over the nine-year duration of the Cap and Trade program. Otherwise, the 232 MMT CO_2e limit might never be reached and the opportunity for lower-cost emissions reductions—and the subsequent control on program costs—is lost. (SCE1)

Response: We did not increase the amount of offsets allowed to be used in the program. The program imposes a limit on the amount of offsets that an individual covered entity can use for compliance. All offsets used for compliance are real reductions, albeit outside the cap. Allowing a limited number of offsets into the program provides cost-containment benefits and ensures that some GHG emissions reductions occur within the sectors covered by the cap-and-trade program. This limit will be enforced through a limit on the use of offsets by an individual entity equal to eight percent of its compliance obligation. Combined with the Allowance Price Containment Reserve, this limit ensures that a majority of reductions from the program come from sources covered by the program at expected allowance prices, while use of the reserve will relax that constraint if prices rise.

We do not agree that there will be insufficient offset supply in the first compliance period. We recently estimated that if every entity used their allowable eight percent offsets, approximately 26 million metric tons of offsets would be needed in the first compliance period. This reduced need is due to a start of the first compliance period in 2013 instead of 2012. At this time, based on the four offset protocols the Board has endorsed—manure digesters, forestry, urban forestry, and destruction of ozone depleting substances—ARB will be close to the supply demand for the first compliance period. We also will consider additional Compliance Offset Protocols beginning in 2012.

The regulation requires that offsets account for eight percent of an individual entity's emissions over a three-year period. We did not allow the carryover of unused offsets within this time frame to ensure that emission reductions are being achieved by capped sources throughout the life of the program. Keeping it to the compliance period allows some flexibility by giving three years to total emissions, but still requiring that emission reductions are coming from within capped sectors in all years of the program.

M-12. Comment: Kern recommends that there be a robust offset market. This will assure cost competitiveness and that the goal of achieving carbon reductions will be accomplished at the lowest cost. To achieve this, it is recommended that CARB increase the offset limit and allow for unused offsets to be carried over to subsequent years. Kern also recommends increasing offset protocols and broader use of offsets in order to spur cooperation of a global nature. Strict limitations of offset quantities and offset protocols (locations) cast a shadow of doubt related to the global nature of this issue. (KERNOIL1)

Response: We did not increase the amount of offsets allowed to be used in the program. The program imposes a limit on the amount of offsets that an individual covered entity can use for compliance. All offsets used for compliance are real reductions, albeit outside the cap. Allowing a limited number of offsets into the program provides cost-containment benefits and ensures that some GHG emissions reductions occur within the sectors covered by the cap-and-trade program. This limit will be enforced through a limit on the use of offsets by an individual entity equal to eight percent of its compliance obligation. Combined with the Allowance Price Containment Reserve, this limit ensures that a majority of reductions from the program come from sources covered by the program at expected allowance prices, while use of the reserve will relax that constraint if prices rise.

The regulation requires that offsets account for eight percent of an individual entity's emissions over a three-year period. We did not allow the carryover of unused offsets within this time frame to ensure that emission reductions are being achieved by capped sources throughout the life of the program. Keeping it to the compliance period allows some flexibility by giving three years to total emissions, but still requires that emission reductions are coming from within capped sectors in all years of the program.

We recognize stakeholder concerns regarding offset supply. ARB is prohibited from adopting additional protocols as part of this cap-and-trade rulemaking. All offset protocols used in the compliance program must be adopted by the Board after undergoing a full regulatory process, including an ARB stakeholder process, in accordance with the Administrative Procedure Act, and an environmental review. We plan to look at further offset protocols for potential inclusion in the cap-and-trade program beginning in 2012. The details surrounding any new offset project types for which ARB adopts an offset protocol will be dealt with under that specific rulemaking, and modification will be made to the cap-and-trade regulation as needed.

M-13. Comment: We believe that individual facilities should not be imposed to a restriction on offsets. The restriction should be on total number of offsets overall allowed into the program. This would give regulated entities that get priced out of the allowance market to go into the offset market for the remainder of their surrender. (AGCOALITION)

> **Response:** We reviewed the options to implement the limit on offsets and, due to the accounting complexity and stakeholder comments from facilities that preferred knowing exactly what was expected with regard to surrendering offsets, we believe an individual facility limit is the optimal approach.

Geographic Limits

M-14. Comment: Section 95973(a)(3), states the offset projects can be done within the U.S., Canada or Mexico; however, it does not specifically identify U.S. Territories. This is inconsistent with the Livestock Manure (Digester) Offset Protocol, which identifies the United States and U.S. Territories. The two should be consistent. Modify section 95973(a)(3) as follows:
(3) be located in the United States and United States Territories, Canada, or Mexico. (SEMPRA1)

> **Response:** We agree and modified section 95973 (a)(3) to also include United States Territories.

M-15. (multiple comments)
Comment: Geographic restrictions and quantitative restrictions do not provide co-benefits. Unlimited and geographically unrestricted offsets will not cause environmental degradation. Offset credits should be allowed without any geographical or quantitative restrictions. (CCEEB1)

Comment: CLFP recommends that the regulation not impose geographic limitations at this time. (CALFP1)

Comment: The amount of offsets that are allowed in the program should be expanded internationally. (SDCHAMBER)

> **Response:** The regulation allows offset projects from North America to be credited under ARB-approved protocols; however, the approved Compliance Offset Protocols are only applicable in the United States and its Territories. We will continue to evaluate whether the four project types already approved for use in the program could be expanded to apply outside of the United States. Any changes to the already adopted protocols will be done as part of a separate rulemaking process to ensure that the GHG reductions and GHG removal enhancements being credited as offsets are real, additional, quantifiable, permanent, verifiable, and enforceable.

Offset credits from projects located outside of North America may also be used for compliance if they are issued by an outside program that is approved by the Board, though no such approval of another program is being evaluated at this time.

Calculation of the Quantitative Limit on Offsets

M-16. Comment: The formula calculating the offset quantitative usage limit should be drafted more clearly. OWG recommends a simpler calculation as follows:

O shall be ≤ S * 0.08, where

O = Total number of compliance instruments that are designated as subject to this quantitative usage limit pursuant to subarticle 4, section 95821(b), (c), and (d) that may be surrendered in the relevant compliance period. Sector-based credits . . .
S = Covered entity's annual or triennial compliance obligation positive or qualified GHG emissions reported in the relevant compliance period.
L = Quantitative offset credit usage limit, set at 0.08. (OFFSETSWG1)

Response: New section 95854(a) was originally expressed as part of the "O" term in the equation in this section, and it was moved into its own section to make it more clear which compliance instruments are subject to the quantitative use limit. This original text was also modified to include a reference to ARB offset credits (section 95820(b)), which was inadvertently omitted from the original regulatory text. The text in new section 95854(b) now references section 95854(a), to make it clear which compliance instruments are subject to the quantitative usage limit. This text, as well as the modified text in the O_o and S terms of the equation, establishes that the quantitative usage limit applies to the triennial compliance obligation and not the annual compliance obligation. This modification was made in response to stakeholder comments. We agree that applying the limit to each annual surrender is overly complicated, and there is no benefit to the program when applying it annually.

We added section 95854(c) to clarify that sector-based offset credits may only be used for up to 25 percent of the eight percent total limit on designated compliance instruments, increasing to one-half of the eight percent in the third and subsequent compliance period.

M-17. Comment: To add clarity, modify section 95820 as follows: (2) Surrender of offset credits shall be subject to the quantitative usage limit set forth in sections <u>95854 and </u>95995. (NCPA1)

Response: We have not made this change because section 95820 refers to ARB offset credits which are issued directly by ARB. These compliance instruments are subject to the quantitative usage limit (section 95854). In addition, ARB may approve sector-based offset credits (identified later in section 95821(d)). Sector-based offset credits are subject to different usage rules than ARB offset credits, therefore, a reference to section 95995 within section 95820 would be misplaced.

M-18. Comment: The following two provisions concerning the offset limit are difficult to interpret taken together. We recommend that they be clarified to state that the total triennial compliance obligation is subject to the quantitative usage limit but that the annual and triennial surrender obligations are not. In other words, a compliance entity may submit, in its triennial surrender (say, 2015), a quantity of offsets equal to eight percent of its total three-year compliance obligation, even if it has submitted no offsets as part of its annual compliance obligations in 2013 and 2014.

- Section 95854: The number of offset credits that each covered entity may surrender to meet its annual or triennial compliance obligation…
- Section 95856(f)(2): The total number of allowances and offset credits submitted to fulfill the combined Annual and Triennial Surrender obligations is subject to the quantitative use limit on offset credits…

Consistent with the cost-reduction purpose of offsets, we recommend that compliance entities be permitted to surrender an unlimited number of offsets in the annual compliance surrender events, understanding that when the triennial compliance obligation is calculated, the total number of offsets credited for the three-year period will be subject to the eight percent limit. In this way, a company can minimize its economic outlay in the first two years, providing capital for investment in onsite emission reductions. Should a company's offset submittals in the first two years exceed the eight percent limit over the whole period as thereafter calculated for the triennial obligation, the excess quantity of offsets would simply remain retired and the allowance surrender obligation adjusted upwards accordingly to equal 92 percent of the entire triennial obligation. (In such a case, the total number of offsets and allowances submitted would exceed the triennial obligation, which is a benefit to the environment; if a company chooses this route, there is no harm to the cap, nor to the offset limit policy). (TPI2)

Response: We modified the language in sections 95854 and 95856(f)(2) to clarify this issue. The regulation now establishes that the quantitative use limit applies to the triennial compliance obligation and not the annual compliance obligation. We made this change because applying the limit to each annual surrender is overly complicated, and there is no benefit to the program when applying it annually.

M-19. Comment: The proposed regulation appears to create annual limits on the use of allowances and offsets. This element of the proposed regulation inappropriately reduces the fungibility of allowances and offsets within the three-year compliance period. This defect should be corrected. If only 2012 allowances are valid for surrender to meet compliance obligations for 2012, as currently stated in section 95856(b)(2) and only eight percent of 2012 compliance obligation can be met with offsets as indicated in section 95854, the three-year compliance period is in actuality a series of one-year compliance obligations. However, during workshops ARB explained its intent that allowances and offsets would be fully fungible during the three-year compliance period to be able to smooth out weather and economic growth variations. Accordingly, offsets should be limited only to eight percent of the triennial compliance obligation; there should be no annual limit. Similarly, the requirement for allowances should be modified to indicate that they must be issued during the same triennial compliance period, or before, unless conditions (A) or (B) are met. Allowances issued for 2013 or 2014 should be allowed to be used in 2012.

Modify section 95854 as follows:

The number of offset credits that each covered entity may surrender to meet its ~~annual or~~ triennial compliance obligation must conform to the following limit:

O/S must be less than L
Where:
O = Total number of compliance instruments that are designated as subject to this quantitative usage limit pursuant to subarticle 4, section 95821(b), (c), and (d).
Sector-based offset credits as defined in section 95821 cannot represent more than 25 percent of O in the first and second compliance periods and 50 percent of O in all other periods.
S = Covered entity's ~~annual or~~ triennial compliance obligation
L = Quantitative offset credit usage limit, set at 0.08.

Modify section 95856(b)(2) as follows:

To fulfill any compliance obligation, a compliance instrument must be issued from an allowance budget year within or before the ~~year during which the compliance obligation is calculated~~, <u>end of the compliance period</u> unless:

(A) the allowance was purchased from the Allowance Price Containment Reserve pursuant to section 95913; or
(B) the allowance is used to satisfy an excess emissions obligation. (SEMPRA1)

> **Response:** We modified the language in section 95854 to clarify this issue. The regulation now establishes that the quantitative use limit applies to the triennial compliance obligation and not the annual compliance obligation. We made this change because applying the limit to each annual surrender is overly complicated, and there is no benefit to the program when applying it annually.
>
> We did not make the change requested to section 95856(b)(2). Allowances issued for a future year cannot be used for surrender in an earlier compliance period. The one exception is an allowance purchased from the reserve, which may be used as soon as it is bought. This approach is proposed to prevent the threat of "cascading borrowing." This situation occurs when entities are able to

use future allowances for current compliance, creating a growing shortage of instruments in later compliance periods.

Sector-Based Offset Limit

M-20. (multiple comments)
Comment: Section 95854 (p. A-68) sets out the eight percent offset limit and imposes a sub-limit on the use of sector-based offset credits. The only rationale provided in the ISOR for limiting the use of sector-based offset credits is that sector-based offset crediting programs are “new and evolving” (ISOR, p. III-25). However, the sector-based offset crediting programs will be subject to the same rigorous review as all other offset programs before ARB will approve them, and the Cap and Trade regulation includes specific criteria for such programs. Once a sectoral program has satisfied these criteria and has been subjected to the full Board approval process, there is no valid basis for restricting the use of sector-based offsets to a greater degree than other types of offsets. Sector-based offsets may provide a valuable source of real, cost-effective emission reductions that benefit the climate, the country of origin, and compliance entities in California, but this potential will be reduced by constraining the demand for such offsets even before sector-based programs have been finalized. The sub-limit on using sector-based offsets should be removed. (SCPPA1)

Comment: EDF has estimated that the number of sector-based offsets allowed for compliance will rise from 3.6 million metric tons (MMT) in 2012 to 14.5 MMT in 2020, with about 80.1 MMT cumulatively over the nine-year period, 2012-2020. Relative to the potential supply, these are low limits will unnecessarily constrain the emissions reductions that can be achieved in these sectors by discourage supplying regions from participating, so it may be prudent to consider raising the quantitative limit on sector-based offsets. (EDF1)

Comment: Dow advises ARB to expeditiously pursue the development of sector-based Reducing Emissions from Deforestation and Forest Degradation (“REDD”) offset criteria that can be adopted in time for use to contain costs in the first and subsequent compliance periods. Establishing sectoral REDD credits holds considerable promise to produce significant quantities of offsets, but the availability of those credits during the first compliance period may be very limited or non-existent due to the need to agree on protocols and other administrative tasks. Even if a large supply of REDD offsets is developed, the use of sectoral credits is capped at 25 percent which translates into 10.6 million metric tons of offsets during the first compliance period. Dow advises ARB to consider temporarily raising this cap if other strategies to establish cost containment during the first compliance period fail to mature. (DOWCHEM1)

Comment: ARB should avoid placing unnecessary limitations on the use of sector-based offset credits, as are currently stipulated under the proposed regulation. Sector-based offsets are limited to 25 percent of the total amount of offsets in the first and second compliance period and 50 percent in the third compliance period. Since sector-based offset crediting will be subject to the same detailed review as other offset programs, and proposed regulation sets forth specific criteria for sector based offsets, it is unclear why ARB would place such restrictions on sector-based offsets. Sector-based offsets are an important opportunity for ARB to develop high quality GHG reductions that are cost-effective and complimentary to the Cap and Trade Program. Accordingly, ARB should encourage the development of the offset market by deleting the limitations on sector-based offsets. (PACIFICOR1)

Comment: CERP is concerned with the phased-in sectoral credit use limit within the offsets usage limit. Under the proposed regulations, regulated entities could only use sectoral offsets for 25 percent of their compliance obligation during the first two compliance periods, and for 50 percent during the third compliance period. If there is a shortage of non-sectoral offsets, and a steady supply of sectoral offsets, this usage constraint will severely and unnecessarily hamper the cost containment value of offsets. CERP urges ARB to modify the regulations to empower the Executive Officer to increase the sectoral offsets usage quota if insufficient quantities of non-sectoral credits are available at reasonable prices. In addition, the calculation of the sectoral offsets limit as described in the proposed regulations enhances the program's vulnerability to non-sectoral offsets shortages. The sectoral offsets usage limit is calculated as a percentage of the offsets an entity turns in for compliance, rather than as a percentage of the offsets usage limit. This means that a shortage in non-sectoral offsets will also constrain the quantity of sectoral offsets that can be used, precisely when they will be most needed for cost containment. It is our understanding that ARB staff members are aware of this problem, which should be rectified. (CERP1)

Comment: It would also be helpful if CARB also ensured that programs focused on emissions stemming from deforestation and/or other forestry and land-use activities, in cases where these sectors are the bulk of total emissions, are not limited to be considered as sector-based offsets but could also potentially qualify to enter the California market as allowances from a GHG ETS specified under section 95942(b) issued by a program approved under section 95941 and not subject to the quantitative usage limit. This would further encourage the development of a robust system of emissions trading that reduces emissions comprehensively and cost-effectively. (EDF1)

Comment: EDF believes that the constraints on sector-based crediting should be according to quality rather than quantity criteria. Rigorous quality standards should ensure the integrity of the environmental goal while providing regulated entities with as much flexibility as possible in terms of how those entities can achieve that goal. The limited size of California's market makes it even more critical not to impose further quantitative constraints so as to ensure a robust demand for REDD and other sector-based credits. (EDF1)

> **Response:** We are maintaining the quantitative limit on sector-based offsets as stated in the regulation. In addition to limiting the use of sector-based offset credits because these programs are new and evolving, the limit on sector-based

offset credits will ensure that California's policy objectives to have offset projects implemented in the State of California will be met.

Ensuring Offset Quality and Criteria of AB 32

M-21. Comment: What sort of comprehensive auditing mechanism will ARB put in place to ensure that offset credits are truly "real, permanent, verifiable, enforceable, quantifiable, and additional"? What mechanism will ARB use to make the system whole? Will ARB audit offset credits? Has the cost of oversight for offset credit auditing been considered? (ASMMANDEVORE3)

Response: The regulation proposes a robust monitoring program for offset projects—both the verification that the offsets are real, additional, and enforceable, and that Offset Project Operators, verifiers, and Offset Project Registries are operating according to regulatory requirements. In addition to the ARB audits, Offset Project Registries are required to conduct oversight of their registry program and randomly audit verifications to ensure that our regulatory requirements are being met by Offset Project Operators and verification bodies.

We will provide rigorous oversight of our approved Offset Project Registries. Each year, the Offset Project Registries will provide us with a report providing basic information related to any offset project listed using a Compliance Offset Protocol and any findings related to verification audits. We will require Offset Project Registries to provide any information related to an offset project when requested by us as part of its oversight of the Offset Project Registry. During the course of an offset project, the Offset Project Registry will track and report any guidance or information provided to an Offset Project Operator related to a compliance offset project to us every month. This will ensure that we understand any issues or concerns related to its compliance offset program as Offset Project Operators are implementing the actual offset projects.

In addition, we designed our regulatory offset verification program to provide a transparent process by which we can review verification documents and fully understand any findings uncovered during the course of verification of an offset project by an ARB-accredited verification body. We will also develop an audit and oversight program for offset project verifications. All oversight functions are part of implementation and need not be specified in the regulation.

Finally, ARB's cost of oversight for offset credit auditing has been considered.

M-22. Comment: Three major criticisms of cap and trade schemes are that either the offsets themselves or the trading practices used to account for them are often not verifiable and are fraudulent, and that they can lead to oppression for indigenous communities. The scoping plan proposes to expand a California cap and trade system to other countries where others might benefit from offsets. Put differently, AB 32 would allow more pollution in California, including co-pollutants that would concentrate in low-income communities of color, with the hope that other countries will allow clean development. This vision fails to consider that these trades are not verifiable, they are often not surplus, they exacerbate the equivalency problem, and they increase the likelihood of oppression. AB 32 specifically requires that the regulations do not disproportionately impact low-income communities, that ARB consider the overall societal benefits of any regulation, and that regulations minimize leakage. These requirements have not been met. (CBE1)

> **Response:** We do not agree the requirements of AB 32 have not been met. We designed the regulation to avoid unintended consequences. However, given the complexity of the program, it is important to incorporate systems to monitor and evaluate the performance of the cap-and-trade program. We propose to monitor emissions leakage, the generation and use of offset credits, and the potential for emissions increases to ensure that the program continues to meet the diverse objectives described in Health and Safety Code sections 38562(b) and 38570(b) over time.
>
> Currently, the regulation does not include any provisions to allow offsets to come from other countries. Before ARB would accept any offsets from developing countries, there would be a separate rulemaking which would include a public process and all applicable analyses required through the APA process.
>
> AB 32 states that ARB must minimize leakage to the extent feasible. The cap-and-trade program is designed to minimize leakage to the extent feasible through the allocation strategy and the accounting for leakage using a principle of conservativeness in the offsets program. Offsets are a small component of the cap-and-trade program, which is only one of the strategies that have been adopted to reduce statewide greenhouse gas emissions. The cap-and-trade program together with the other complementary measures that have been adopted meet the requirements of AB 32 in this area.
>
> The regulation proposes a robust monitoring program for offset projects—both the verification that the offsets are real, additional, and enforceable, and that Offset Project Operators, verifiers, and Offset Project Registries are operating according to regulatory requirements. Offset Project Registries are required to conduct oversight of their registry program and randomly audit verifications to ensure that our regulatory requirements are being met by Offset Project Operators and verification bodies. We will provide rigorous oversight of our approved Offset Project Registries. In addition, we designed our regulatory offset verification program to provide a transparent process by which we can review verification documents and fully understand any findings uncovered during the course of verification of an offset project by an ARB-accredited verification body. We will also develop an audit and oversight program for offset project verifications. All oversight functions are part of implementation and need not be specified in the regulation.

The regulation provides a framework for allowances and offsets from other approved programs (such as another cap-and-trade program, an offset registry, or a sector-based crediting program) to be used to meet compliance obligations. The regulation establishes a process by which each program would be evaluated on a case-by-case basis before being considered by the Board. In approving an external program, the Board would also specify what compliance instruments from that program would be accepted for compliance use in California's program. Recognition of another program's compliance instruments or linkage would be implemented by program-specific contracts or memoranda of understandings, as applicable.

Our analysis indicates that the cap-and-trade regulation is expected to have a beneficial impact on air emissions by reducing emissions of criteria pollutants and toxics. Based on the available data, current law and policies that control industrial sources of air pollution, and expected compliance responses, we believe that emission increases due to the regulation at the statewide, regional, or local level are extremely unlikely, at best. Nevertheless, we are committed to monitoring the implementation of the cap-and-trade regulation to identify any situations where the cap-and-trade program has led to an increase in criteria pollutant or toxic emissions. We will also solicit information from local air districts regarding permit modifications and new permit applications for covered sources. This information will be used to identify compliance activities that could lead to increased emissions, and to determine whether further investigation of potential criteria pollutant and toxic emissions is warranted. If unanticipated adverse localized emissions impacts that can be attributed to the cap-and-trade regulation are identified during this periodic review, we will consider whether these impacts affect the achievement of the program objectives. If so, we will promptly develop and implement appropriate responses. Potential responses we would consider include, but are not limited to, supporting the use of allowance value from the cap-and-trade program to mitigate localized emissions increases, providing incentives for energy efficiency and other emissions-reduction activities within the community, or restricting trading or prohibiting certain compliance responses in specifically identified communities. These potential future responses are not, however, warranted based on currently available information, and their imposition today would unnecessarily conflict with AB 32's other objectives.

M-23. Comment: I strongly disagree with the use of offsets as a means to implement AB 32, and particularly to offsets outside of California. It appears it would be impossible to verify that offsets are "real, permanent, quantifiable, verifiable, enforceable, and additional," given the lack of any proposed objective method to determine if such standards are met. Further, it is easy to conceive of methods for shady businesses to profit through manipulation. The obvious concern is that businesses will create a multi-billion "cottage" industry to exploit the system by feigning that an activity is "additional," and the state will be hamstrung to prove otherwise, all while emission reduction targets are missed. California cannot afford to allow key, targeted polluting sectors to avoid reducing greenhouse gas emissions or to create perverse incentives to develop an offset industry. (REAVES)

> **Response:** We disagree that offsets cannot be verified or meet the requirements of AB 32. The regulation proposes a robust monitoring program for offset projects—both the verification that the offsets are real, additional, and enforceable, and that Offset Project Operators, verifiers, and Offset Project Registries are operating according to regulatory requirements. Offset Project Registries are required to conduct oversight of their registry program and randomly audit verifications to ensure that our regulatory requirements are being met by Offset Project Operators and verification bodies. We will provide rigorous oversight of our approved Offset Project Registries. In addition, we designed our regulatory offset verification program to provide a transparent process by which we can review verification documents and fully understand any findings uncovered during the course of verification of an offset project by an ARB accredited verification body. We will also develop an audit and oversight program for offset project verifications and offset project developers and these audits will be conducted by ARB. All oversight functions are part of implementation and need not be specified in the regulation.
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> We disagree that the inclusion of offsets does not require capped sources to reduce emissions. The program imposes what we believe is an appropriate limit on the amount of offsets that an individual covered entity can use for compliance. All offsets used for compliance are real reductions, albeit outside the cap. Allowing a limited number of offsets into the program provides cost-containment benefits and ensures that some GHG emissions reductions occur within the sectors covered by the cap-and-trade program. The program includes provisions that would allow a maximum of 201 $MMTCO_2e$ of offsets through the year 2020. This limit will be enforced through a limit on the use of offsets by an individual entity equal to eight percent of its compliance obligation, or total emissions. Combined with the Allowance Price Containment Reserve, this limit ensures that reductions from the program come from sources covered by the program at expected allowance prices, while use of the reserve will relax that constraint if prices rise.
>
> In regard to additionality, we believe that the Compliance Offset Protocols, in conjunction with all of the strict and thorough requirements in the regulation regarding offsets, meet the requirements of AB 32. The Compliance Offset Protocols adopted under the cap-and-trade regulation have been established with multiple levels of review, use conservative methods to account for uncertainty and emissions leakage, and to establish the additionality of offset projects in setting project baselines.

M-24. Comment: Offsets allow developed countries to ignore legally binding emission reduction commitments. With offsets, developed countries can continue to produce more than their fair share of emissions, at a time in which reductions are required by all nations, but particularly by those historically responsible for the problem. This is not merely stating the fact as a matter of equity, but it is required by the Framework Convention on Climate Change, the international agreement signed by most nations in the early 1990s, committing developed countries to reduce their emissions, and to provide "new and additional" money to less-developed nations to help them with clean development and climate-change mitigation. This assistance to the developed world was very clearly meant to be in addition to, not instead of, immediate emissions reductions on the part of the developed world.

Offsets create a disincentive for technological innovation for the buyers of credits. While companies selling credits—that is, those which emit at a level below that of their carbon allocation—have an incentive to innovate, companies in highly polluting industries have no incentive as long as credits are available to them at rates lower than the anticipated cost of reduced emissions. Why should they innovate or even start on the research and development that would be required? More broadly, the existence of offsets postpones the major structural changes necessary for developed countries to switch to a low-carbon infrastructure, and allows their worst polluters to continue to emit greenhouse gases when they should be actively winding them down.

Offsets create disincentives for quicker paths to emission reductions. Offsets approved by the UN's Clean Development Mechanism executive board must be, among other things, additional to greenhouse gas reduction activity that would have occurred anyway. This rule, set for obvious reasons with respect to the purpose of the program, unfortunately creates a perverse disincentive to new programs of regulation and/or taxation in regions of sellers of certificates, usually the developing world. If more stringent regulations were set, they would limit eligibility for some projects that might have been granted approval otherwise, undercutting the inward flow of capital.

Markets do not plan and are unconcerned with equity or transparency. Relying on market forces to create clean development in the developing world removes that activity from any transparent public planning process that considers sustainability, equity, or regional economic need.

Less-developed countries are forgotten. Development projects have been disproportionately located where industrial infrastructure is already well-established—that is China, India, Mexico and Brazil (now collectively about 80 percent of all projects)—leaving less-developed nations with little inflow of money for mitigation and clean development. Offsets, along with speculation, should be eliminated from the program. (MAGILAVY)

> **Response:** We disagree that the inclusion of offsets does not require capped sources to reduce emissions. The program imposes a limit on what we believe is an appropriate amount of offsets that an individual covered entity can use for compliance. All offsets used for compliance are real reductions, albeit outside the cap. Allowing a limited number of offsets into the program provides cost-containment benefits and ensures that some GHG emissions reductions occur

within the sectors covered by the cap-and-trade program. The program includes provisions that would allow a maximum of 201 $MMTCO_2e$ of offsets through the year 2020. This limit will be enforced through a limit on the use of offsets by an individual entity equal to eight percent of its compliance obligation, or total emissions. Combined with the Allowance Price Containment Reserve, this limit ensures that reductions from the program come from sources covered by the program at expected allowance prices, while use of the reserve will relax that constraint if prices rise.

We disagree with the statements about additionality. We believe that the Compliance Offset Protocols in conjunction with all of the strict and thorough requirements in the regulation regarding offsets meet the requirements of AB 32. The Compliance Offset Protocols adopted under the cap-and-trade regulation have been established with multiple levels of review, use conservative methods to account for uncertainty and emissions leakage and to establish the additionality of offset projects in setting project baselines. Moreover, the offsets currently approved in the program under the four protocols may only result from GHG reductions or sequestration in the United States. We have not approved any offsets from other countries and have not approved any offsets developed under the Clean Development Mechanism (CDM). Our offsets program is designed very differently than the CDM by relying on standardized assessments of additionality established by ARB through a public process and not relying on project-specific assessments done by the project developers themselves.

Currently, we do not have any provisions for offsets to be developed outside of the United States. We will continue to evaluate whether the four project types already approved for use in the program could be expanded to apply outside of the United States. Any changes to the already adopted protocols will be done as part of a separate rulemaking process, to ensure that the GHG reductions and GHG removal enhancements being credited as offsets are real, additional, quantifiable, permanent, verifiable, and enforceable.

M-25. Comment: Offsets do not and will not provide real emissions reductions. They will offset the responsibility of the State and polluting industries. This will allow pollution in California to continue both in the form of CO_2 emissions and in the form of the more immediate toxic threats from refineries, incinerators, power plants and so on. This will lead to the kinds of immediate health impacts we see around the Richmond refineries, Kettleman City, West Oakland, Fresno, and other industrial impacted areas. I would recommend that offset allowances within AB 32 be kept to a minimum in order to truly encourage clean and green economic alternatives for California. (GJEP1, GJEP2)

Response: We disagree that the offsets in our program do not provide real reductions. We believe that the Compliance Offset Protocols, in conjunction with all of the strict and thorough requirements in the regulation regarding offsets, meet the requirements of AB 32. The Compliance Offset Protocols adopted under the cap-and-trade regulation have been established with multiple levels of review, use conservative methods to account for uncertainty and emissions leakage and to establish the additionality of offset projects in setting project baselines.

We disagree that the inclusion of offsets does not require capped sources to reduce emissions. The program imposes a limit on what we believe is an appropriate amount of offsets that an individual covered entity can use for compliance. All offsets used for compliance are real reductions, albeit outside the cap. Allowing a limited number of offsets into the program provides cost-containment benefits and ensures that some GHG emissions reductions occur within the sectors covered by the cap-and-trade program. The program includes provisions that would allow a maximum of 201 $MMTCO_2e$ of offsets through the year 2020. This limit will be enforced through a limit on the use of offsets by an individual entity equal to eight percent of its compliance obligation, or total emissions. Combined with the Allowance Price Containment Reserve, this limit ensures that reductions from the program come from sources covered by the program at expected allowance prices, while use of the reserve will relax that constraint if prices rise.

M-26. Comment: None of the offset types described under the Offset Protocols under discussion for AB 32 could ever be demonstrated to be real, permanent, quantifiable, verifiable, enforceable, or additional. Hence they do not meet AB 32 requirements and should be rejected. Offsets would play an even more egregious role undermining AB 32 than emissions trading proper, for additional reasons involving verifiability, reflexivity, counter productivity and environmental and social damage that have been well-rehearsed in the peer-reviewed literature. (CORNERHOUSE)

Response: We disagree with these statements. We believe offsets are real GHG reductions, albeit it from outside the cap. We believe that the Compliance Offset Protocols in conjunction with all of the strict and thorough requirements in the regulation regarding offsets meet the requirements of AB 32. The Compliance Offset Protocols adopted under the cap-and-trade regulation have been established with multiple levels of review, use conservative methods to account for uncertainty and emissions leakage and to establish the additionality of offset projects in setting project baselines. To assure offset quality, the program includes rigorous oversight and audit procedures for all ARB-accredited offset verifiers, offset project developers, and Offset Project Registries. In addition, the registry system for compliance instruments is being designed to provide strong enforcement capabilities, including mechanisms to prevent double-counting, public disclosure requirements, and methods to clearly define ownership.

M-27. (multiple comments)
Comment: Carbon offsets are a means to allow companies to buy their way out of responsibility for cutting their own emissions with theoretical reductions elsewhere. The fundamental problems with this scheme include:

- Shifting Responsibility: Offsetting does not reduce emissions at the source, but allows companies to buy credits from elsewhere.
- Selling stories: Offsetting rests on “additionality” claims about what “would otherwise have happened.” The net result for the climate is that offsetting tends to increase rather than reduce greenhouse gas emissions, displacing the necessity to act in one location by a theoretical claim to act differently in another. Moreover, countries that host offset projects have a new barrier to the implementation of environmental regulations, since to do so would remove “additionality” and thereby cut of potential revenue.
- Making things the same: The value of CDM projects is premised on constructing a whole series of dubious “equivalences” between very different economic and industrial practices, with the uncertainties of comparison overlooked to ensure that a single commodity can be constructed and exchanged. This does not alter the fact that burning more coal and oil is in no way eliminated by building more hydro- electric dams, planting monoculture tree plantations or capturing the methane in coal mines.
- Offsets burst the cap: While cap and trade in theory limits the availability of pollution permits, offset projects are a license to print new ones.
- Carbon offsets subsidize increased greenhouse gas emissions: One of the most frequent justifications put forward for carbon offsets is that they should ensure that the cheapest reductions are made first. In practice, these tend to be generated by loopholes and generous subsidies for the deployment of existing technologies, rather than stimulating shifts to a more sustainable future. (CTW)

Comment: Within the cap and trade system, offsets represent an alternative means of achieving legislated emission reductions. They enable reductions to occur outside regulated sectors, and can be more cost effective than onsite reduction at regulated emission sources. However, if emission reductions which result from “business as usual” activities are allowed as emission offsets, the emissions cap could be exceeded and the legislated quantity of emission reductions will not be achieved. (TPI1)

> **Response:** We disagree that the inclusion of offsets allows entities to buy their way out of reducing emissions on site. The program imposes a limit on what we believe is an appropriate amount of offsets that an individual covered entity can use for compliance. All offsets used for compliance are real reductions, albeit outside the cap. Allowing a limited number of offsets into the program provides cost-containment benefits and ensures that some GHG emissions reductions occur within the sectors covered by the cap-and-trade program. The program includes provisions that would allow a maximum of 201 $MMTCO_2e$ of offsets through the year 2020. This limit will be enforced through a limit on the use of offsets by an individual entity equal to eight percent of its compliance obligation, or total emissions. Combined with the Allowance Price Containment Reserve, this limit ensures that reductions from the program come from sources covered by the program at expected allowance prices, while use of the reserve will relax that constraint if prices rise. By establishing an allowance budget in the

regulation and quantitative offset usage limit, we believe there will be no "bursting of the cap."

We believe that the Compliance Offset Protocols, in conjunction with all of the strict and thorough requirements in the regulation regarding offsets, meet the requirements of AB 32. The Compliance Offset Protocols adopted under the cap-and-trade regulation have been established with multiple levels of review, use conservative methods to account for uncertainty and emissions leakage, and to establish the additionality of offset projects in setting project baselines. Moreover, the offsets currently approved in the program may only result from GHG reductions or sequestration in the United States. We have not approved any offsets from other countries and have not approved any offsets developed under the Clean Development Mechanism (CDM). Our offsets program is designed very differently than the CDM by relying on standardized assessments of additionality established by ARB through a public process and not relying on project-specific assessments done by the project developers themselves.

M-28. Comment: AB 32 requires that greenhouse gas ("GHG") offsets be "real, permanent, quantifiable, verifiable, enforceable, and additional." Adoption of the proposed Offset Protocols by the California Air Resources Board is arbitrary and capricious and should be rejected because the protocols for proposed GHG offsets cannot meet these standards. In addition, to the extent that GHG offsets are not additional, they destroy the integrity of the entire program by allowing additional GHG emissions from the capped sector above the "cap" that will not be offset by additional emission reductions elsewhere. Finally, because California's program is looked to as a model and proof of concept, adoption of this flawed mechanism would be extremely damaging to national and international efforts to effectively reduce GHG emissions. Adoption of GHG offsets as part of the California program would serve as a template for such programs, encouraging others to pursue this flawed approach to the most urgent problem facing humanity, increasing the chances of catastrophic climate change, and defeating the stated purpose of AB 32. Under the proposed action, "covered entities can use offset credits to satisfy up to eight percent of the entity's total compliance obligations." See Notice of Public Hearing at p. 5. This eight percent of the compliance obligation is very significant percentage of the total reductions sought.

To be credited as an offset, the staff report states that a project "must also be additional to what is required by law or regulation <u>or would otherwise have occurred</u>." See ARB Staff Report, page 35 of 472. (Emphasis added). Our analysis focuses primarily on the latter requirement. As demonstrated in our Whistleblower Disclosure ("Williams/Zabel Disclosure"), dated July 22, 2010) http://www.carbonfees.org/home/Whistleblower_Disclosure_to_Congress_7-21-10.pdf), GHG offsets of the type that ARB proposed to adopt are fatally flawed and cannot be fixed. There is no reliable way to distinguish offset projects which will occur because of the offset incentive from those which would have happened anyway because of the following four unfixable flaws of GHG Offsets:

Additionality: Whether reductions outside the capped sector are additional is necessarily a hypothetical inquiry and such an inquiry cannot reliably distinguish business-as-usual. Specifically, it is impossible to know what "otherwise would have occurred" and therefore it is not possible to create an offset program that reliably excludes business-as usual activities from being counted as "additional." (See U.S. Government Accountability Office discussion below, confirming this conclusion).

Leakage/Shifting Economic Activity: In some cases, such as in the context of forestry projects, the offsets will fail to appreciably mitigate demand and the polluting activity (such as logging) will simply shift elsewhere;

Perverse Incentives to Increase Emissions and Keep Them Legal: GHG offsets create perverse incentives to keep polluting activities legal and in some cases to increase them, so they can keep being sold as offsets (Note: this dynamic is recognized in the Ozone Depleting Substances ("ODS") Protocol re: HCFC-22 by-product HFC-23 destruction in the United Nations Clean Development Mechanism ("CDM"), see ODS Protocol at p. 11 of 67); and

Unenforceable: The complexity and subjectivity of offsets renders them impossible to certify, regulate or enforce.

As explained in our discussion below of each of the four proposed offset protocols suffers from one or more of these flaws and would result in approval of non-additional projects in violation of AB 32. As a result, it would be arbitrary and capricious to adopt the proposed GHG offset protocols as part of the proposed Cap and Trade program. See also, U.S. Government Accountability Office, March 2009 ―Observations on the Potential Role of Carbon Offsets in Climate Change Legislation‖ at p. 12, GAO-09-456T (http://www.gao.gov/new.items/d09456t.pdf). "Because additionality is based on projections of what would have occurred in the absence of the CDM [United Nations Clean Development Mechanism], which are necessarily hypothetical, it is impossible to know with certainty whether any given project is additional."

Keeping Our Eyes on the Wrong Ball - Offsets are described in the Staff Report as a "cost containment mechanism," which offers additional low-cost emissions-reduction opportunities. See Staff Report at page 14 of 472. However, cost containment interferes with another goal cited in the Staff Report—to "stimulate investment in clean and efficient technologies." See Staff Report at page 11 of 472. Keeping the price of fossil fuel emissions lower by allowing offsets delays investment in clean energy technologies and energy efficiency by keeping fossil fuels cost competitive. As a result, such "cost containment" defeats the goal of a rapid transition to clean energy and energy efficiency. See http://www.carbonfees.org/home/Cap-and-TradeVsCarbonFees.pdf (WILLIAMSZ)

> **Response:** We disagree that the inclusion of offsets does not require capped sources to reduce emissions. The program imposes a limit on what we believe is an appropriate amount of offsets that an individual covered entity can use for

compliance. All offsets used for compliance are real reductions, albeit outside the cap. Allowing a limited number of offsets into the program provides cost-containment benefits and ensures that some GHG emissions reductions occur within the sectors covered by the cap-and-trade program. The program includes provisions that would allow a maximum of 201 $MMTCO_2e$ of offsets through the year 2020. This limit will be enforced through a limit on the use of offsets by an individual entity equal to eight percent of its compliance obligation, or total emissions. Combined with the Allowance Price Containment Reserve, this limit ensures that reductions from the program come from sources covered by the program at expected allowance prices, while use of the reserve will relax that constraint if prices rise. In addition, California's cap-and-trade program only allows offsets to equal up to eight percent of an entity's compliance obligation, as opposed to the early phases of the EU ETS and the federal cap-and-trade bills proposed in recent years. For example, the Waxman-Markey bill would have allowed 30 percent offsets at the start of the program and 60 percent by 2050. We advocated then and still believe that offsets provide an important role in the program by providing cost-containment benefits, but that they do need to be limited to require capped entities to make meaningful emission reductions at the source. We believe the limited use of offsets in our program will serve as a good template for new proposals at the federal level.

We disagree with the statements about additionality. We believe that the Compliance Offset Protocols, in conjunction with all of the strict and thorough requirements in the regulation regarding offsets, meet the requirements of AB 32. The Compliance Offset Protocols adopted under the cap-and-trade regulation have been established with multiple levels of review, use conservative methods to account for uncertainty and emissions leakage and to establish the additionality of offset projects in setting project baselines. Moreover, the offsets currently approved in the program may only result from GHG reductions or sequestration in the United States. We have not approved any offsets from other countries and have not approved any offsets developed under the Clean Development Mechanism (CDM). Our offsets program is designed very differently than the CDM by relying on standardized assessments of additionality established by ARB through a public process and not relying on project-specific assessments done by the project developers themselves.

To ensure that reductions or removals credited as offsets are real, the regulation requires that all Compliance Offset Protocols address activity-shifting and market-shifting leakage. Each protocol incorporated by reference, including the forest protocol, accounts for leakage in the quantification of the reductions or removals achieved by the offset projects. In addition, when uncertainty exists in quantifying GHG reductions, ARB will only issue offset credits when there is a high level of confidence that reductions actually occurred. The regulation employs a principle of conservativeness in the quantification of emissions reductions. This method will ensure that the accounting will underestimate rather than overestimate any reductions when there is a high level of uncertainty.

Furthermore, ARB's Compliance Offset Protocol for Ozone Depleting Substances Projects does not credit the destruction of HFC-23, and only credits the destruction of gases that have been phased out, originate in the United States, and only exist in banks that would otherwise leak into the atmosphere. Therefore, under ARB's protocol there are no perverse incentives to produce these gases.

ARB has full enforcement and oversight authority over all offset project developers, offset verifiers and verification bodies, and Offset Project Registries. ARB can disallow offset issuance to a project developer, revoke or suspend the accreditation of ARB-accredited verifiers, and revoke or suspend the approval of Offset Project Registries. In addition, the regulation requires all users of offset credits to replace them to ARB in the event they are found to be invalid after issuance.

In addition to stimulating investment in clean energy technologies and energy efficiency in capped sectors, another goal of the cap-and-trade program is to "support the development of innovative projects and technologies from sources outside capped sectors that can play a key role in reducing emissions both inside and outside California" through the inclusion of offsets (page ES-4 and ES-5 of the Staff Report). Through a combination of the declining cap and the limited use of offsets, both goals can be met.

M-29. Comment: Offset projects involving livestock manure, ozone depleting substances, and forestry mentioned in the proposal under review have a well-documented international record of being particularly damaging not only to the climate, but to local economies and the environment. HFC-23 offsets, for instance, have caused a scandal at the level of the United Nations Framework Convention on Climate Change because of their climatically-damaging effects due to perverse incentives for production of additional greenhouse gas. Livestock manure projects in Mexico and elsewhere are subject to the same problem and are also provoking heavy public resistance, as are REDD and other carbon forestry projects worldwide. (CORNERHOUSE)

Response: All offset protocols used in the compliance program must be adopted by the Board after undergoing a full regulatory process in accordance with the Administrative Procedure Act. Before the Board adopts a new protocol there will be a separate CEQA review to assess the environmental impacts associated with that protocol. In addition, offset protocols include several elements to support existing health and environmental protection measures. Specifically, each individual offset protocol requires all offset projects to be developed in compliance with all federal, state, and local laws, regulations, ordinances, and any other legal mandate, including all CEQA and National Environmental Policy Act (NEPA) requirements where applicable. The Offset Project Operator is required to attest to ARB that their offset project meets these requirements. If, during verification, it is found that the offset project does not meet any of these requirements, the project is ineligible to be issued ARB offset credits until the project is in compliance. In addition to regulatory compliance, during project listing, Offset Project Operators must provide detailed project information, which must be posted on the Internet and available for public review.

Furthermore, ARB's Compliance Offset Protocol for Ozone Depleting Substances Projects does not credit the destruction of HFC-23 and only credits the destruction of gases that have been phased out, originate in the United States, and only exist in banks that would otherwise leak into the atmosphere. Therefore, under ARB's protocol there are no perverse incentives to produce these gases.

M-30. Comment: We are concerned with the proposed use of agricultural offsets. Our understanding was that the CO_2 reductions from agriculture were determined to be too difficult to verify or quantify to include it in the cap, yet your proposed draft allows for offsets from these same sources. How will these emission reductions be verified or quantified? (FRESNOMINISTRY)

Response: Currently, the only offset protocols that are approved for agriculture is the reduction of methane from livestock manure digesters. We believe this protocol is rigorous and accurately quantifies the emission reductions achieved by digester projects. Any new offset protocols must be approved by the Board to ensure projects meet the high standards intended under AB 32 (must be real, permanent, quantifiable, verifiable, enforceable, and additional). The Board will consider adopting additional compliance offset protocols in a separate rulemaking in the near future and will work with our WCI partners in this regard.

M-31. (multiple comments)
Comment: Safeguards against manipulation and other forms of fraudulent behavior would be beneficial, including additional provisions to guard against double counting of offsets in multiple systems. While section 95985(a) partially addresses this concern, further restrictions may be necessary to prevent the same offset credits from being sold more than once in different markets. Linkage agreements and coordination efforts between CA and other programs may help address this concern, as well as the requirement of an additional attestation from Offset Project Operators regarding this concern. (CCAP1)

Comment: CARB should devise a means of ensuring that the same offset project is not available for sale through multiple registries throughout North America and not sold more than once. (WALTERS, UCS1, LUDLOW)

Comment: Ensure that offsets cannot be sold more than once through different registries. (VARON)

Response: New section 95975(c)(5) of the regulation now requires that an Offset Project Operator or Authorized Project Designee disclose any offset credits issued for the same project for any other purposes in any other program. In addition, we added new attestations to section 95981(c). Offset Project Operators and Authorized Project Designees must make these attestation(s) in order for ARB to issue offset credits. Also, if ARB finds that ARB offset credits were issued to the offset project for the same GHG reductions or GHG removal enhancements, ARB may invalidate the ARB offset credits pursuant to section 95985. This provision addresses double-counting of the GHG reductions or GHG removal enhancements in multiple programs.

M-32. Comment: Board should close potential loopholes in the offset process by giving the Executive Officer explicit authority to deny any offset proposals that do not meet standards, and should ensure that the same offset project cannot be sold more than once through different registries. (SIERRACLUBCA4)

Response: We agree with the suggested change. The Board gave the Executive Officer the authority over offset proposals. In addition, we added language in the verification section to delete Offset Project Registries from the appeals process for Adverse Verification statements. This clarification was made to be consistent with the MRR and reflects stakeholder comments that the appeals process should only be limited to determinations made by the Executive Officer of ARB and that ARB should be the only one to make these determinations. We also clarified that ARB makes the final determination on whether or not ARB offsets credits should be issued and meet all requirements of the regulation, and we added this text to the regulation.

In addition we added new section 95975(c)(5) to the regulation that now requires Offset Project Operators or Authorized Project Designees to disclose any offset credits issued for the same project for any other purposes in any other program. In addition, we added new attestations to section 95981(c). Offset Project Operators and Authorized Project Designees must make these attestation(s) in order for ARB to issue offset credits. Also, if ARB finds that ARB offset credits were issued to the offset project for the same GHG reductions or GHG removal enhancements, ARB may invalidate the ARB offset credits pursuant to section 95985. This provision addresses double-counting of the GHG reductions or GHG removal enhancements in multiple programs.

M-33. Comment: In addition to potentially encouraging a move to anaerobic conditions so that a dairy would qualify for offsets, the Digester Protocol also creates an incentive for additional market participants to oppose regulation that would require either aerobic treatment or an anaerobic digester. As noted with respect to the other Protocols and in the Williams/Zabel Disclosure, normal regulatory evolution would move in the direction of prohibiting activities that are found to be harmful in significant ways that were not previously appreciated or known. In this case, all facilities that engage in anaerobic storage of manure for more than 150 cows could potentially be required to use a biogas control system and destroy or sell the resulting methane for energy. A law that creates an offset market for this activity creates opposition to a comprehensive regulation that would remove this activity from the offset market and deprive these market participants of the related revenue, creating instead an obligation that has associated costs. The heightened opposition to such regulation should be analyzed as part of "what otherwise would occur," in order to fully consider whether the proposed offset protocol creates truly additional reductions outside the capped sector. (WILLIAMSZ)

> **Response:** Regulatory additionality is assessed based on the regulatory environment at the time of implementation of the offset project. Additionality is not intended to look at what types of regulations could potentially be implemented in the future. The purpose of the offsets program is to incent actions to reduce GHG emissions for those activities that are not already required or being implemented as part current practices. In addition, ARB will periodically assess all offset project types to determine if they are still additional. If a new law is passed, or an activity has become common practice, no new offset projects would be able to be implemented. As such, it is not practical or technically accurate to consider an activity unadditional because there may be some unforeseen regulations that could be implemented in the future.

M-34. (multiple comments)
Comment: Imposing the most stringent regulatory additionality requirement across multiple legal jurisdictions needlessly wastes low-cost emission reduction opportunities. The staff report suggests that ARB's intent is to define additionality such that the most stringent regulatory requirement in any jurisdiction will be assumed to be in effect in all of the other jurisdictions throughout the Western Climate Initiative (WCI). Our understanding is that this "regulatory additionality" proposal is based on an assumption that the availability of income from offsets would discourage other jurisdictions from adopting regulations such as those in California—and, conversely, that denying such income would encourage promulgation of such regulations. In our view, this assumption is highly speculative, and rather reductionist. States adopt rules, or do not adopt them, for any number of reasons. The ARB's proposal seems to overstate the influence of the California offsets program on policies in other states.

This account also understates the possibility that California's offsets program could promote promulgation of new regulations, e.g., by providing financial incentives for the installation of emission capture technologies, thereby making it easier for other jurisdictions to later require their use. If California's offsets program were to help make certain abatement activities in other states effectively "business-as-usual," such activities would no longer qualify for offset credits and there would be little resistance to a regulatory requirement that they be maintained. In any event, there is no reason to make an a priori assumption about the influence of the California offsets program on other jurisdictions. A better approach would be to launch the program without this "regulatory additionality" proposal. If, after some initial period of time, there is evidence that the California offset rules are discouraging other jurisdictions from adopting regulations similar to those in the California system, the relevant offset project type(s) could be made ineligible. CERP strongly urges ARB to revisit this approach because it will deny California and the WCI system the benefit of any number of emission reduction projects that are truly additional, thereby constricting offset supply and increasing compliance costs. (CERP1)

Comment: Baselines should be established with reference to the laws and regulations that apply in the jurisdiction in which the offset project is located. The highest WCI standards should not be used to set baselines. That would be inappropriate and would substantially reduce the number of viable offset projects. Using jurisdiction-specific standards will not be a disincentive for that jurisdiction to shift towards more stringent standards. Countries, states, and provinces have many reasons for enacting (or not enacting) more stringent environmental regulations and pursuing clean-energy goals. Whether or not a jurisdiction takes these steps has little to do with whether some entities in that jurisdiction may be able to earn offsets for particular activities. Therefore there is no reason to set baselines according to the highest WCI standards rather than local regulations. The types of “early action” offsets allowed to be used for compliance should be expanded to include all CAR offsets (Climate Reserve Tons or “CRTs”). (SCPPA2)

> **Response:** The decision to only include offset projects that qualify based on a regional additionality test throughout the WCI was made by the Partners to ensure that offset projects will be developed in WCI Partner jurisdictions and to ensure that a portion of the revenues generated from offsets would be generated in-state. WCI Partners do not want to create a program that pays parties in other states and provinces to undertake activities that they are requiring their sources to undertake by capping them or applying other direct regulations to such activities.

M-35. Comment: CARB should evaluate conservative crediting of emissions reductions and consideration of uncertainty in the aggregate across a pool of individual projects to account for uncertainty, thereby allowing for expansion of scientific knowledge during the lifetime of specified emissions reduction projects without disqualifying that project from the start. (EDF1)

> **Response:** When uncertainty exists in quantifying GHG reductions, we propose to employ a principle of conservativeness in the quantification of emissions reductions. In the cap-and-trade offsets program, the quantification methods are established in a Compliance Offset Protocol. Our offsets program relies on standardized assessments of additionality established by ARB through a public process and not relying on project-specific assessments. This method will ensure that the accounting will underestimate rather than overestimate any reductions when there is a high level of uncertainty. We believe this approach is important to the environmental integrity of the program.

Offset Supply and Additional Offset Protocols

M-36. Comment: There is an apparent inconsistency. The supply of offsets is given to be "Q = (P-8)/0.75" where P is the allowance price (page N-8 of Appendix E). In a prior document, the offset supply is given to be "Q = (P-8)/0.15" (Updated Economic Analysis of Scoping Plan March 24, 2010). Based on the offset supply numbers presented in CARB's latest analysis, it is not clear which of the two offset supply formulas is the correct one. (CAPCOA1, CAPCOA2)

> **Response:** For the Scoping Plan analysis, we used an offset supply curve that looked at the cumulative supply for all years of a cap-and-trade program. The formula Q = (P-8)/0.15 represents the total quantity of offsets as a function of the 2020 allowance price.
>
> In Appendix N of the Staff Report, we used an offset supply curve for each individual year of a cap-and-trade program. The formula Q = (P-8)/0.75, represents the quantity of a given year's offsets as a function of that year's allowance price.

M-37. (multiple comments)
Comment: SCPPA's chief concern is that ARB's approach to the offsets program, both its own protocols and links to other offset programs, is so restrictive and will be finalized so late that not enough offsets will be available at the start of the cap and trade program to contain compliance costs. The ARB's own projections indicate that in some scenarios the demand for offsets will significantly exceed supply. The ARB should make every effort to avoid this outcome, given the key role of offsets in cost containment as repeatedly confirmed in the economic analyses of the cap and trade program. High-quality offset programs currently exist, including the Climate Action Reserve (CAR) and the Clean Development Mechanism under the Kyoto Protocol (CDM). These up-and-running programs should be utilized more fully. (SCPPA2)

Comment: NCPA appreciates CARB's recognition of the important role that offsets will play in the California program. However, as currently contemplated, there are an insufficient number of qualified offset project available to California compliance entities. CARB must move expeditiously towards approving additional offset protocols. (NCPA1)

Comment: ARB should enact certification protocols for a broader array of projects in the very near term to help ensure that a sufficient supply of offset credits will be available. Given the incipient nature of the offset market and its potential to achieve significant GHG emission reductions within California, nationally, and globally, we urge ARB to find ways to encourage the development of a robust offset market and not place seemingly-arbitrary restrictions on the use or certification of offsets. (PACIFICOR1)

Comment: In these difficult economic times, it is imperative that there be a robust supply of quality offsets to mitigate the cost of complying with the many requirements of AB 32, especially as under CARB's Scoping Plan only approximately 20 percent of the

State's GHG emission reductions are to come from market-based mechanisms. Offset projects achieve GHG emission reductions now. Millions of tons of GHGs have been reduced over the last 15 years in the U.S. through the voluntary offsets market. This experience can be deployed quickly to create a pool of low-cost GHG emissions reductions for covered facilities under the regulation, thereby promoting many of the goals of AB 32. (COPC1)

Comment: One of CERP's primary concerns with the proposed Cap and Trade regulations is that the offset program will not generate sufficient offsets to meet the demand anticipated and provide the cost containment needed. The draft regulations would create an offset program with an early action component, but the program is limited to only four project types. Of the four project types, only projects to destroy ozone-depleting substances (ODS) are projected to generate significant offset volume in the near term. Because of the structure of the offsets program and the limited number of offset project types, CERP is concerned that there will not be enough offsets, and that the program will be overly dependent upon a single offset project type. There are simple but important changes that would help remedy this situation. (CERP1)

Comment: The ARB Board Resolution adopting final AB 32 regulation should reflect the Staff Report's statement on the importance of linkage and offset availability. We are concerned that ARB's limited approval process and the adoption of only four protocols will impact offset supply. We have detailed recommendations to help ensure that a large supply of offsets will be available. We believe it is vital that these be proposed and approved in early 2011 so that an offset supply can develop prior to the launch of the market. (CHEVRON1)

Comment: CARB should consider how to assure an ample supply of high-quality offsets to help companies comply with carbon reduction strategies in a cost-effective manner. As the new economic study shows, offsets will play a critical role in the successful implementation of AB 32 and provide a link to a future national framework as well as to international carbon markets. (LADWP1)

Comment: PG&E believes that offsets will help California advance the goals of AB 32 while containing the overall cost to the California economy. I'm concerned about the supply of offsets based on my experience with the Climate Smart program. In the first compliance period, estimates are that we will have less than half the necessary volume that will be allowed. There are four different ways that we can work to address that supply. 1) Approve the four reserve protocols: Coal mine methane, Nitric acid production, organic waste diversion, and organic waste composting. The Board should also consider the Article 5 Ozone Depleting Substance Protocol. Take a look at the comments from Eos Climate; 2) Approve existing protocols from other bodies, such as the American Carbon Reserve's fertilizer management protocol; 3) Develop infrastructure necessary for offsets from REDD, Reducing Emissions From Deforestation and Forest Degradation. We're encouraged by the MOU that California has with Chiapas and Acre, Brazil, and encourage ARB to develop the working group recommendations outlined in the MOU. They allow ARB to allow REDD offsets within the first compliance period; and 4) Consider offsets from the capture of methane from landfills. This one-time use of offsets between the period of 2005 and 2011 will allow a necessary volume. (PGE1, PGE3)

Comment: CARB should expand the list of eligible domestic offset protocols. (CONOCO)

Comment: We encourage CARB to consider the inclusion of other offset protocols outside of the four protocols currently under consideration. (CALCHAMBER1)

Comment: ARB must be more aggressive in promoting the use of offsets by increasing the speed at which offset protocols are adopted. (WSPA1, WSPA2)

Comment: We welcome CARB's initial selection of protocols and encourage CARB to set in place measures to expand the list of protocols available to compliance entities, so long as there is harmonization with other environmental and regulatory objectives in the state. For example, we do believe there is logic in CARB's exclusion of landfill gas projects but would note that landfill projects in Mexico are among the most clear-cut cases of high quality, additional offsets in that many are little more than large uncontrolled trash dumps where there are few incentives to control, secure, and sanitize the site other than via implementing a landfill gas carbon project. (CLIMATEWEDGE)

Comment: Work with stakeholders to expand the supply of offsets. Under the proposed rule, up to 42.5 million tons of offsets would be allowed during the first compliance period. Given the thin volumes currently available, it appears very unlikely that supply would match demand in the first compliance period. The supply of offsets in the second and third compliance periods would need to more than twice as large in order for the cost containment benefit of offsets to be achieved. Dow is concerned that this mismatch between supply and potential demand will extend into the second and third compliance periods unless ARB expeditiously undertakes measures that will enable the offsets program to more fully serve its intended purpose. Dow recommends that ARB continue to coordinate with the US EPA, WCI partners, and others states and provinces throughout North America and beyond to consider how best to make real and legitimate cost containment available to those entities in California that are becoming the first in North America to become subject to added costs of a cap and trade program.

In addition to providing needed cost containment, enabling more robust offset provisions is likely to build greater acceptance and support for the concept of cap and trade in jurisdictions that are still considering its merits. The largest benefit to the climate that may be experienced by the California cap and trade program is not the significant reductions achieved but the absence of economic hardship that might otherwise result if cost containment mechanisms are not fully functional during the first compliance period (DOWCHEM1)

Comment: According to ARB’s analysis of offset supply for the California program, projects involving destruction of ozone depleting substances (ODS) are projected to supply 91 percent of the available offsets between 2012 and 2020. To be sure, ODS destruction projects can provide high quality, cost-effective offset credits and are therefore an important source of cost containment. However, in our view, it is risky to place such a heavy reliance on one offset project type to generate essentially all of the cost containment for the Cap and Trade program. CERP urges ARB to facilitate the generation of emission reductions by authorizing a diverse portfolio of offset project types, and to focus initially on offset project types that can generate cost-effective offsets in the near term. (CERP1)

Comment: Based on the criteria above, ARB should take every effort to identify protocols in addition to the four Climate Action Reserve (CAR) protocols already part of the proposed rules. By making this declaration, ARB will stimulate immediate investment in these project types, increasing the likelihood of availability of low-cost offset supply early in the program. As such, Evolution Markets recommends consideration of the following project types: Destruction of Landfill Gas Methane; Destruction of Coal Mine Methane/Ventilated Air Methane; Destruction of Ozone Depleting Substances from Countries Outside of the U.S.; Destruction of N_2O; Agricultural Practices. (EVMKTS)

Comment: In general, more strong signals are needed for the market to continue to invest in offset projects. At this stage, significant investment capital is not being deployed because of the continued uncertainty on project types in California's cap-and-trade market, most notably in the coal mine methane sector. At this stage, the voluntary market alone is not enough to incentivize investment in highly uncertain project types such as coal mine methane. The sooner the ARB provides clear signals to market, the sooner capital investment will flow to the next set of project types, and the sooner California see early offsets supply. (EVMKTS)

Comment: TFI recommends development of guidance related to the requirements and procedure for the acceptance of additional offset protocols. We believe that the protocol list must be expanded to meet the offset demand and contain costs of the program. As such, it is critical to have a transparent and efficient process for additional protocol approval. (Subarticle 13: section 95971) (TFI)

Comment: Develop offset protocols that can create credits for the use of recycled materials. (SFMAYOR1)

Comment: CARB Board should consider including landfill gas (LFG) destruction as an offset protocol. It is understood that compliant entities under California's Market-Based Compliance Mechanism were initially allowed to meet up to 4 percent of their obligation with offsets—and that has increased to eight percent (223 $MtCO_2e$) in this final draft. As we know, it will be hard enough sourcing 223 $MtCO_2e$ worth of offsets from just four protocols that CARB has initially put forward (urban forestry, forestry, livestock methane and the destruction of ozone depleting substances) even if sourced from other partner jurisdictions. When demand for offsets cannot be satisfied, their increased price will diminish their value as a least cost alternative for meeting compliance requirements; this hurts overall liquidity, increases costs of compliance, and may defeat any successful functioning of California's Market-Based Compliance Mechanism. Including LFG destruction as a fifth protocol will help mitigate the risk of California's Market-Based Compliance Mechanism from getting a "black eye" due to the above-mentioned liquidity and cost of compliance problem introduced by not getting enough offsets into the marketplace. It is understood that within California, new air quality rules requiring LFG collection preclude most California located landfills from becoming eligible offset projects. However, there are many partner jurisdictions within WCI that could contribute greatly to California's coming offset need and great demand, by providing said offsets sourced from "CAR protocol verified and registered" LFG destruction projects. (FRC)

Comment: There are two key existing protocols that can be approved today to help address the threat of lack of supply: landfill gas from North America and coal mine methane.

1) The landfill gas protocol could increase supply by 54 percent or 3.1MM credits.
   - Through 2009, there are 104 landfill gas projects receiving credits from CAR only 5 of which are from California.
   - Therefore, the protocol must not exclude non California projects, or it will not serve to improve supply.
2) Coal mine methane has the potential to supply over 50 million tons in offsets through 2020 according to sources within CAR. (CHEVRON1)

Comment: The four offset protocols identified in ARB’s proposed regulations are unlikely to produce the level of offsets needed to provide the desired level of cost containment during the first compliance period. The cost and timing of developing these offsets and making them available for AB 32 cap and trade cost containment purposes also remains very uncertain.

Allow Landfill Gas Offsets. To help ensure adequate volume during the first compliance period, Dow recommends that ARB reconsider its prohibition on the use of landfill gas credits by California entities. Landfill gas offsets from throughout North America (except in jurisdictions where capture is required) should be allowed for compliance purposes during the first compliance period. There are approximately four million metric tons of offsets verified under the CAR’s Landfill Gas protocol with significant potential untapped potential in the first compliance period. Enabling the use of landfill gas offsets is necessary to meet the forecasted demand during the first compliance period. (DOWCHEM1)

Comment: Pursue development of additional offset protocols, including a wetlands protocol. ARB staff solicited public input on which offset project types should be pursued. Dow provided comments indicating that wetlands were an important potential offset typology that provided both GHG mitigation benefits and adaptation co-benefits. While there are steps that need to take place before new offset protocols can be written, (e.g., pilot projects, research, funding, etc.), these and other offsets will be needed in future compliance periods. ARB received a variety of other recommendations on offset typologies to develop. These recommendations should be documented and included in a written plan that would put the ARB on track to provide a fully functioning cost containment mechanism in future years of the program. (DOWCHEM1)

Comment: The agricultural community has been conducting research and will continue to work on the development of offset protocols. There are many challenges due to the large diversity of crops and ecosystems. The Climate Action Reserve will soon begin work on three new agricultural protocols and there are other agricultural protocols further developed that need more on-farm testing to insure they can achieve GHG reductions in a manner that is compatible with California conditions and can be readily used by growers. We request that the board direct the CARB staff to give agricultural protocols a high priority and work closely with CAR and other providers to insure a thorough and timely review process to enable additional offsets become available. (ACC1)

Comment: All agricultural offset protocols developed by CARB should account for the carbon footprint of the whole farm or ranch production system. Current USDA research on grain cropping systems in Maryland finds that when comparing organic, no-till and conventional tillage agricultural production systems, the total carbon footprint of the organic system is lower than the no-till and conventional tillage production systems. While the organic system, in some years, had higher NO_2 emissions compared to the no-till and conventional tillage systems, those periodically higher NO_2 emissions were offset by lower overall CO_2 and CH_4 emissions. This research provides one example of the imperative to consider the entire farming system in order to accurately assess and manifest the opportunities within agriculture to provide real and significant GHG emissions reductions. (CACAN1, CACAN2)

Comment: California agriculture is beginning at a disadvantage in being able to participate in offset programs because we are already implementing modern practices and because of the regulatory environment rules already on the books and those that are scheduled to move forward will prevent California agriculture from creating an offset while a neighboring state or country can implement the same practice and get paid for it. Another impediment is our diversity of crop and crop rotations which limits us to longer term contracts that are required by the standards. Additional direction from the Board is needed to ensure that the standards will allow California agriculture to participate in offset development in a large scale. (AGCOALITION)

Comment: CARB should pay special attention to make sure agricultural sector stakeholders are involved and opportunities to reduce emissions in this sector are maximized, subject to the robust criteria established by CARB, various protocols such as wetland, nitric acid reduction, fertilizer production, and rice methane reduction. As part of this effort by CARB, current work in the field by non-regulatory entities ought to be encouraged and utilized by CARB. (EDF1)

Comment: Production of bio-based products should be included in a list of eligible offset project types. Improvements in land utilization associated with the production of renewable biomass should be eligible for carbon offset credits on a basis comparable to other activities eligible for carbon offset credits. (ERICKSON)

Comment: Considering the significant quantities of purely additional methane that are currently being vented to the atmosphere by coal mine ventilation systems, we recommend the following:

- Recognize ventilation air methane (VAM) oxidation as an eligible offset category for the first compliance period;
- Adopt a coal mine methane (CMM) VAM protocol based on Climate Action Reserve's (CAR) existing CMM Project Protocol;
- Recognize VAM carbon reduction tons (CRT) generated by projects started after October 7, 2007.

In support of these recommendations are the following

- Methane is the second most important greenhouse gas, after CO_2;
- The global warming potential of methane has recently been revised by the Intergovernmental Panel on Climate Change (IPCC) from an initial value of 21 to a current value of 25, while anthropogenic methane emissions are expected to increase by 23 percent by 2020;
- By accepting VAM as an eligible offset project category, the CARB will support crucial US and international efforts to reduce methane emissions and fight climate change;
- The protocols currently adopted by CARB could lead to a shortage of offsets;
- VAM offsets are available throughout the entire carbon credit price spectrum, including at low carbon credit prices. They are a low-cost offset and ensure a strategic diversification of offset sources, and can significantly contribute to lowering CARB's shortage in offset supply.
- VAM projects need support from a regulated carbon market.
- The CAR's CMM Protocol should provide the CARB with the necessary base to adopt a CMM protocol. We believe it is highly compatible with the Western Climate Initiative criteria, apart from a few necessary modifications. It is crucial that this adoption take place as soon as 2011 in order to send a strong signal to project developers and further encourage the destruction of methane currently being vented to the atmosphere. (BTINC)

Comment: CARB has indicated that currently it will only accept four project types as offset credits: Forestry, Livestock, Urban Forestry, and Ozone Depleting Substances (ODS). Given the small scale of Livestock and Urban Forestry, CARB is highly dependent on the supply of credits provided by Forestry and ODS. This could severely limit offset supply, as few landowners have thus far agreed to the 100-year forest management commitment and there are other competing uses for ODS. In order to provide adequate cost containment, we believe that CARB should include easily measurable and verifiable coal mine methane and landfill methane projects as eligible offset types. (CE2CP)

Comment: Two key protocols, landfill gas for North America and coal mine methane have been developed and used by the Climate Action Registry for several years. We recommend that these be considered by ARB in early 2011. The North America landfill gas protocol would add over 50 percent more offsets in the first compliance period. The coal mine methane protocol holds the potential to provide a large supply of valuable and verifiable offsets that could ensure that AB 32 emission reductions are achieved cost-effectively. (WSPA1, WSPA2)

Comment: Evolution Markets defends and advocates for well functioning, liquid markets and believes that so long as the quality and integrity of the offset is safeguarded through the application of the stringent criteria the ARB has identified for offsets, all project types meeting the ARB's regulations and the ARB's criteria should be included in the program. To ensure adequate offsets are available at the outset of the program, as well as sufficient market liquidity, Evolution Markets believes the ARB should provide in January 2010 a Policy Statement stating the ARB's intent to allow any offset project type from an uncapped sector so long as it meets the ARB's stated offset requirements. (EVMKTS)

Comment: In the event that ARB is selective of specific protocols under a given registry (e.g., CAR), we strongly suggest that ARB review and approve the CAR Nitric Acid Protocol Version 1 and subsequent versions as amended by CAR, for the same reasons ARB accepted the CAR ozone depleting substances (ODS) protocol. The Nitric Acid Protocol is very critical for the supply of high quality and high volume offsets in the early years of the program and clearly meets ARB's requirements listed in Article 5, Subarticle 13, sections 95972 and 95973. (Subarticle 13: section 95973 (a.2.C)) (TFI)

Comment: In order to ensure sufficient offset supply, it will be critically important for ARB to adopt additional protocols. CERP urges ARB to adopt additional protocols in early 2011. In addition, because it takes some time to finance and develop offset projects, CERP also encourages ARB to publicly identify, as soon as possible, the protocols being considered for adoption. CERP urges ARB to focus first on project types for which there are well-established methodologies or that have the potential to generate large quantities of emission reductions. Project types with established methodologies include methane collection at landfills, coal mines, and natural gas systems and non-landfill projects that involve collection, combustion, or avoidance of emissions from organic waste streams. Project types that have the potential to generate large quantities of emission reductions include agricultural projects involving nutrient and rangeland management. (CERP1)

Comment: CARB should expand the opportunity for agricultural and forest offsets. CARB should develop a clear confidentiality framework specific to agriculture projects and operations and with input from offset project developers. (EDF1)

Comment: Because climate change is a global problem that requires a global solution and because California will continue to be negatively impacted if regions outside the state do not act, CARB should re-evaluate the restrictive quantitative limits on the use of offsets while hastening and widening the approval of offset protocols to ensure adequate supply. The regulation should be designed to ensure introduction to the market of the full allowed quantity of offsets. (BP)

Comment: Offset credits allowed for mitigating CO_2 emissions in the PDR were limited to four percent. The proposed Cap and Trade Regulation raises the allowable percentage to eight percent. Additionally, there are only four offset protocols that CARB is currently considering for approval. As the number of available allowances declines, there will be increased need to additional and creative offset projects both inside and outside California. Therefore, more flexibility needs to be built into this aspect of the Cap and Trade Regulation, as well as an expedited approval process for new offsets. (MWDSC1)

> **Response:** We recognize stakeholder concerns regarding offset supply. ARB is prohibited from adopting additional protocols as part of this cap-and-trade rulemaking. All offset protocols used in the compliance program must be adopted by the Board after undergoing a full regulatory process, including an ARB stakeholder process, in accordance with the Administrative Procedure Act, and an environmental review. We plan to look at further offset protocols for potential inclusion in the cap-and-trade program beginning in 2012. The details surrounding any new offset project types for which ARB adopts an offset protocol will be dealt with under that specific rulemaking, and modification will be made to the cap-and-trade regulation as needed.
>
> In addition, ARB is looking at protocols developed by third parties, as well as other voluntary and regulatory offset programs, and may not rely on one program to the development of offset protocols.

M-38. Comment: A significant lack of clarity remains over the details concerning how CARB will actually certify additional offset protocols and registries. (EDF1)

> **Response:** We recognize stakeholder concerns regarding offset supply. ARB is prohibited from adopting additional protocols as part of this cap-and-trade rulemaking. All offset protocols used in the compliance program must be adopted by the Board after undergoing a full regulatory process, including an ARB stakeholder process, in accordance with the Administrative Procedure Act, and an environmental review. We plan to look at further offset protocols for potential inclusion in the cap-and-trade program beginning in 2012. The details surrounding any new offset project types for which ARB adopts an offset protocol will be dealt with under that specific rulemaking, and modification will be made to the cap-and-trade regulation as needed.
>
> We have provided a role for Offset Project Registries (OPR) to perform some of the administrative functions of the offset process in the regulation. We plan to utilize OPRs in lieu of performing these duties itself in the short-term, and may

choose to continue this throughout the program. ARB has not yet determined if and when it would itself perform these roles. Therefore, in the meantime all parties seeking to use Compliance Offset Protocols must go directly to an OPR to list their projects. ARB plans to approve OPRs sometime in 2012.

M-39. (multiple comments)
Comment: The offset protocols receiving initial consideration are those currently established by the Climate Action Reserve, which represent the protocols judged to be easiest to be established and representing significant quantities of carbon dioxide. Linkage is also expected with the Western Climate Initiative. Within the area served by the WCI, there are other appropriate standards, such as ISO-14064-2. These other standards should also be allowable, particularly, if the quantification and verification analyses were done within the WCI territories. It could have a major impact within the industry without compromising integrity. (MCLAUGHLIN)

Comment: Approve the use of the following Climate Action Reserve protocols: Coal Mine Methane; Mexico Livestock; Nitric Acid Production; Organic Waste Composting; and Organic Waste Digestion. None of these five protocols has generated any CAR CRTs (offsets) as of November 2010 and projected offsets during the first compliance period appear to be small relative to what may be needed (and allowed). Offsets from WCI partner jurisdictions appear unlikely to provide significant volume during California's first compliance period. (DOWCHEM1)

Comment: If we place constraints on finding low-cost offsets in the name of obtaining local co-benefits or creating local "green jobs," California will inhibit the adoption of similar GHG policies in other nations. Instead, ARB should move rapidly to adopt offset protocols and recognize other national and international offset programs, while establishing a process early for developing projects in California. CCEEB recommends that ARB adopt protocols rapidly to ensure that adequate supply is available in the first compliance period. Additional supply options should include:

a) Use of five additional Climate Action Reserve Protocols;
b) Use of offsets from Western Climate Initiative Partners;
c) Support the development of Pilot REDD Projects;
d) Allow use of Climate Action Reserve Landfill Credits generated before 2012;
e) Approve protocols developed by California air districts, as appropriate.

(CCEEB1, CCEEB2)

Comment: Offsets are vital to a healthy market to ensure allowance availability and price control. There is too little reliance on existing offsets protocols developed in other programs and registries. (LASD1)

Comment: Very rigorous voluntary protocols do exist and quality offsets have been generated under them. They should be recognized. (COPC2)

Comment: The Reserve also strongly encourages the Air Resources Board to consider additional standardized, performance-based protocols that are comprehensive and rigorous for inclusion in the cap and trade program. Adopting additional high-quality protocols will ensure that the cap and trade program has an adequate supply of offset credits at a reasonable cost. (CAR1, CAR2)

Comment: SCPPA's chief concern is that ARB's approach to the offsets program, both its own protocols and links to other offset programs, is so restrictive and will be finalized so late that not enough offsets will be available at the start of the cap and trade program to contain compliance costs. The ARB's own projections indicate that in some scenarios the demand for offsets will significantly exceed supply. The ARB should make every effort to avoid this outcome, given the key role of offsets in cost containment as repeatedly confirmed in the economic analyses of the cap and trade program. High-quality offset programs currently exist, including the Climate Action Reserve (CAR) and the Clean Development Mechanism under the Kyoto Protocol (CDM). These up-and-running programs should be utilized more fully. (SCPPA2)

Comment: Evolution Markets recommends ARB consider establishing clear criteria for additional project types that may qualify for early action—criteria that is predicated on the inclusion of projects that can quickly generate large volumes of offset credits. Recommended criteria may include:

High Quality: Offset protocols must be of the highest quality. Therefore, they create offsets that are real, additional, quantifiable, permanent, verifiable and enforceable.

Reputable Standards: Offset protocols must be originated by standards agencies with consistent and long-term reputations for integrity. Furthermore, ARB should consider the adoption of protocols from standards agencies that already have a broad set of accredited and experienced verifiers.

Abundant Issued Supply: ARB should also choose the next round of standards qualifying for early action based on the availability of supply. Consideration should be made to protocols that meet the above criteria and have an existing abundant supply of issued offsets that can be immediately traded in the market. (EVMKTS)

Comment: ARB's entire list of initial qualifying protocols have been developed by CAR. Evolution Markets fully supports the inclusion of offset protocols from CAR, but we also encourage ARB to consider protocols from other well established offsets standards agencies. This would increase the capacity to generate acceptable protocols, and therefore offset supply. (EVMKTS)

Comment: It is not clear whether protocols already created by other programs might be accepted, and whether each protocol will be required to undergo the CEQA process. (VCS)

Comment: We support ARB's intent to develop its own offset protocols through a public process and discourage reliance on Climate Action Reserve protocols. We support ARB's intent to develop new offset protocols through a public process involving stakeholder engagement. We have been in discussions with staff regarding opportunities for offsets in the wastewater sector and look forward to continuing these discussions. Because the Climate Action Reserve (CAR) has the ability to select members for its protocol development working groups, we do not believe that their process is equivalent to a stakeholder process that would be undertaken by ARB. In several instances, we have been excluded from these working groups and our stakeholder input has therefore not been considered. In light of these concerns, we strongly caution ARB against adopting CAR protocols without opening them up to a full new stakeholder process, and we encourage development of new ARB protocols instead. (CAWWCCG1)

Comment: The American Biogas Council believes that compliance offset protocols should include organic waste digester projects. The current compliance offset protocols for Urban Forest Projects, U.S. Ozone Depleting Substances, Livestock Manure (Digester) Projects and U.S. Forest Projects originated from project protocols developed by Climate Action Reserve (CAR) and later adopted by ARB for early action projects. The American Biogas Council urges ARB to follow a similar path in developing an organic waste digestion compliance offset protocol. CAR developed an Organic Waste Digestion Project Protocol which was adopted by its Board on October 9, 2009. Furthermore, the United Nations Framework Convention on Climate Change through the Clean Development Mechanism has adopted offset protocols for organic waste digestion. We are confident that organic waste digestion offset projects can meet the strong accounting and real GHG reduction standards and requirements of AB 32 and thus should be included. (ABC)

Comment: The risks associated with an insufficient supply of offsets should be addressed by accepting offsets from existing offset programs, such as CAR and CDM, adopting more ARB offset protocols, and broadening the application of ARB protocols. (SCPPA2)

Comment: IETA is concerned limiting eligible offsets to these four project types alone would cause an immediate supply shortage. We feel there are simply not enough offsets presently available under these four protocols to provide the market with sufficient supply in the early years of the program to effectively mitigate costs to California consumers. Additional paths for generating offset credits should be explored and incorporated into California's Cap and Trade program. Emission reductions from all qualified existing CAR projects should be brought into the compliance system and become compliance eligible. In addition, ARB should consider recognizing protocols from other high-quality carbon project standards organizations, such as the Voluntary Carbon Standard and the Gold Standard. (IETA1)

Comment: While necessary approaches, like the nesting of project-level emissions reductions within sub-national programs are being worked out, project developers are keen to know which protocols/methodologies they should invest time in understanding and applying to the design of prospective projects. We would encourage ARB to consider as streamlined a process as possible—while ensuring the highest standards of quality—in reviewing and approving appropriate protocols and methodologies from established voluntary standards and registries like the American Carbon Registry, Climate Action Reserve, and especially the Voluntary Carbon Standard as it is the most widely-used and robust voluntary standard in use around the world. The recognition by California of the Voluntary Carbon Standard for compliance-based purposes would send a clear signal to project developers and governments around the world that the voluntary market has the tools and robustness to be integrated with the regulated market, and we can thus address climate change more quickly and effectively. (SUNONESOLUT)

> **Response:** We recognize stakeholder concerns regarding offset supply. ARB is prohibited from adopting additional protocols as part of this cap-and-trade rulemaking. All offset protocols used in the compliance program must be adopted by the Board after undergoing a full regulatory process, including an ARB stakeholder process, in accordance with the Administrative Procedure Act, and an environmental review. We plan to look at further offset protocols for potential inclusion in the cap-and-trade program beginning in 2012. The details surrounding any new offset project types for which ARB adopts an offset protocol will be dealt with under that specific rulemaking, and modification will be made to the cap-and-trade regulation as needed.
>
> In addition, ARB is looking at protocols developed by third parties, as well as other voluntary and regulatory offset programs, and may not rely on one program to the development of offset protocols.

M-40. Comment: To provide this cost-control feature, there must be a sufficient number of qualifying, cost-effective emission reduction opportunities outside the regulated community to supply the emitters' demand or quota for offset credits. If offsets are scarce relative to demand, prices will be dictated by the demand signal and will not be connected to the underlying emission reduction costs, thus destroying the cost-control benefit. The ISOR includes an offset supply analysis for the time period from 2012 through 2020, but does not provide enough detail to assess whether the market will be fully supplied at each of the compliance surrender dates. While there is necessarily considerable guesswork in estimating offset supply in the 2020 timeframe, there is considerably less guesswork in estimating supply in the first compliance period since it's so near at hand.

TerraPass has completed a bottom-up analysis of livestock methane offset availability, and made reasonable top-down estimates of forestry and ozone-depleting substance projects. Separately, carbon industry research organizations such as PointCarbon have published their own estimates. TerraPass estimates that approximately 20 million metric tons of offsets could be available by the end of 2014, while industry research estimates are closer to 27 million. Both of these figures are significantly less than the 39 million tons required to fully supply the market. In addition, TerraPass believes that offsets created in calendar year 2014 cannot be relied upon for the large 2015 compliance submission.

Vintage 2014 offsets will not be verified until late in the year of 2015, just before the compliance submission is due. Since offset projects carry many delivery risks, offset credit owners who make 2015 delivery commitments to emitters will likely limit those commitments to credits of vintage 2013 and earlier. This reduces the supply available for the 2015 submittal by several million tons. There are many uncertainties and assumptions buried within these large estimates, and they could be very far off in either direction.

Also, the buying behavior of emitters is difficult to predict. Even so, a well-supplied marketplace makes quite unnecessary any precise supply models or sophisticated market behavior predictions. (TPl1)

> **Response:** We recognize stakeholder concerns regarding offset supply. ARB is prohibited from adopting additional protocols as part of this cap-and-trade rulemaking. All offset protocols used in the compliance program must be adopted by the Board after undergoing a full regulatory process, including an ARB stakeholder process, in accordance with the Administrative Procedure Act, and an environmental review. We plan to look at further offset protocols for potential inclusion in the cap-and-trade program beginning in 2012. The details surrounding any new offset project types for which ARB adopts an offset protocol will be dealt with under that specific rulemaking, and modification will be made to the cap-and-trade regulation as needed.
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> We recently estimated that if every entity used their allowable eight percent offsets, approximately 26 million metric tons of offsets would be needed in the first compliance period. This reduced need is due to a start of the first compliance period in 2013 instead of 2012. At this time, based on the four offset protocols the Board has endorsed—manure digesters, forestry, urban forestry, and destruction of ozone depleting substances—ARB will be close to the supply demand for the first compliance period. We also will consider additional Compliance Offset Protocols beginning in 2012.

M-41. (multiple comments)
Comment: We support ARB's intent to develop new offset protocols through a public process involving stakeholder engagement. Because the Climate Action Reserve (CAR) has the ability to select members for its protocol development working groups, we do not believe that their process is equivalent to a stakeholder process that would be undertaken by ARB. In several instances, we have been excluded from these working groups and our stakeholder input has therefore not been considered. In light of these concerns, we strongly caution ARB against adopting CAR protocols without opening them up to a full new stakeholder process, and we encourage development of new ARB protocols instead. (EMWD, BACWAAC)

Comment: The preliminary list of acceptable offset must be expanded. To facilitate the offset protocol review and acceptance process, we recommend that ARB simply select a registry pursuant to the requirements established in sections 95972 and 95973, rather than being selective of the specific protocol within the registry/program itself. (TFI)

Response: We recognize stakeholder concerns regarding offset supply. ARB is prohibited from adopting additional protocols as part of this cap-and-trade rulemaking. All offset protocols used in the compliance program must be adopted by the Board after undergoing a full regulatory process, including an ARB stakeholder process, in accordance with the Administrative Procedure Act, and an environmental review. We plan to look at further offset protocols for potential inclusion in the cap-and-trade program beginning in 2012. The details surrounding any new offset project types for which ARB adopts an offset protocol will be dealt with under that specific rulemaking, and modification will be made to the cap-and-trade regulation as needed.

A public process convened by a voluntary program cannot substitute for a stakeholder process conducted by ARB for rulemaking purposes.

M-42. Comment: The array of offsets recommended appears unduly limited. The Program should provide for opportunities for offsets which can be implemented in local communities as an element of economic development or satisfaction of California Environmental Quality Act (CEQA) mitigation requirements. (ASMDICKINSON)

Response: We recognize stakeholder concerns regarding offset supply. ARB is prohibited from adopting additional protocols as part of this cap-and-trade rulemaking. All offset protocols used in the compliance program must be adopted by the Board after undergoing a full regulatory process, including an ARB stakeholder process, in accordance with the Administrative Procedure Act, and an environmental review. We plan to look at further offset protocols for potential inclusion in the cap-and-trade program beginning in 2012. The details surrounding any new offset project types for which ARB adopts an offset protocol will be dealt with under that specific rulemaking, and modification will be made to the cap-and-trade regulation as needed.

Our first priority for adopting additional protocols is to look at project types that can be done in-state. Achieving the goal of climate stabilization will require a commitment to work at the international level to reduce GHG emissions globally. Although we encourage offset projects to be developed in California, we recognize out-of-state projects will expand the scope of the program to allow for more low-cost GHG reduction possibilities to be incorporated and reduce the overall costs of the program. Therefore, ARB will consider expanding the programs to provide offset credits for projects located in the United States, Canada, and Mexico.

To address stakeholder concerns about double-crediting, any offset used for CEQA mitigation is ineligible for use in the cap-and-trade program.

M-43. (multiple comments)
Comment: ARB's offset supply forecasts indicate a heavy reliance on one protocol—the destruction of ozone-depleting substances ("ODS")—to provide the needed offsets. The ARB should prioritize the development of additional protocols that are likely to result in significant numbers of offsets. The initial four ARB offset protocols should not be restricted to U.S. projects only. Projects across North America should be allowed. The ISOR notes (at III-10) that the initial ARB offset protocols being proposed are applicable to offset projects in the United States and its territories only, with potential for expansion to Canada and Mexico at a later stage. Given the urgent need for an early supply of offsets, ARB protocols should cover the US, Canada, and Mexico from the start of the cap and trade program if the necessary technical data is available for each country. The ISOR indicates (at III-5) that ARB staff will periodically propose additional offset protocols. SCPPA encourages the staff to determine which additional protocols are likely to provide the greatest supply of offsets within a relatively brief timeframe and to publish this list of priority protocols together with an indicative timeline for developing these protocols and having them approved by ARB. Additional protocols should be developed to increase offset supply as soon as possible to allow project developers to establish projects, generate emission reductions, and earn offsets for sale in time for the start of the cap and trade program. Having a greater number of offset protocols available will reduce the risk of an offset shortage. (SCPPA2)

Comment: ARB needs to expand the list of eligible offset projects and develop certification protocols for these additional project types. NextEra Energy feels the current list of project types is too limited and fails to maximize the program's potential. There are several other types of projects that could be incorporated into the cap and trade program relatively easily. Some of these project types include but are not limited to: Expanding ODS to imported substances from Mexico or Canada; N_2O abatement; Wastewater management; Coal mine methane. The expansion of this list can increase the amount of projects developed. More offset projects will decrease the cost of the offsets to purchasers of offset credits and therefore the cost of the program on consumers. It will also provide investors an opportunity to develop diverse portfolio of project types. In addition, the total amount of co-benefits associated with these offset projects will increase with more projects being developed. (NEXTERAENERGY)

Comment: Expand the Geographic Scope of CAR Protocols to North America. ARB should modify existing and new Climate Action Reserve protocols to allow for their use for projects located throughout North America. This is similar to the approach being taken to adopt the forest and livestock protocols for use in Mexico. While this approach may not allow offsets markets to mature in time to serve cost containment needs in the first compliance period, it would likely make a significant difference in the second and third compliance periods. (DOWCHEM1)

> **Response:** We recognize stakeholder concerns regarding offset supply. ARB is prohibited from adopting additional protocols as part of this cap-and-trade rulemaking. All offset protocols used in the compliance program must be adopted by the Board after undergoing a full regulatory process, including an

ARB stakeholder process, in accordance with the Administrative Procedure Act, and an environmental review. We plan to look at further offset protocols for potential inclusion in the cap-and-trade program beginning in 2012. The details surrounding any new offset project types for which ARB adopts an offset protocol will be dealt with under that specific rulemaking, and modification will be made to the cap-and-trade regulation as needed.

We will continue to evaluate whether the four project types already approved for use in the program could be expanded to apply to projects located in the United States, U.S territories, Canada, and Mexico. Any changes to the already adopted protocols will be done as part of a separate rulemaking process to ensure that the GHG reductions and GHG removal enhancements being credited as offsets are real, additional, quantifiable, permanent, verifiable, and enforceable.

M-44. Comment: SCE recognizes that CARB is attempting to ensure that offset credits represent emissions reductions that are real, permanent, quantifiable, verifiable, enforceable, and additional, as required by AB 32. Nonetheless, SCE is concerned that CARB staff have created overly complex processes for the development and approval of offsets that may unduly limit the available supply. For example, the four initial offset protocols that were recommended simultaneously with the proposed regulation must first go through a complicated, and likely lengthy, approval process by CARB and then a complex implementation design process involving CARB staff. For these four initial protocols, all of these steps must take place between January 2011 and December 2011 in order for covered entities to include tradable offsets in their compliance strategies by January 2012, when the Cap and Trade program begins. Currently, this scenario seems extremely unlikely. All other offset projects must go through the same approval process and sequence, and even the four offset protocols already in motion are unlikely to provide a robust supply of offsets until late in the first compliance period. Accordingly, those covered entities planning to use offsets as part of their compliance strategies are left with great uncertainty as to whether such offsets will be available. SCE offers the following recommendations for CARB to quickly increase the supply and use of available high-quality, low-cost offsets.

- CARB should remove the geographic limits on the first four offset protocols. Expansion to projects throughout North America would provide more incentives for offset development. SCE continues to support CARB's determination during the scoping plan process that it would not place geographic limits on the origin of offset credits.

- CARB should provide for expeditious approval of offset credits from existing and future offset projects operating under specific offset protocols beyond the four currently being proposed. For example, the Climate Action Reserve ("CAR") has already developed and is continuing to develop about 60 MMT worth of additional voluntary offset credits through its existing offsets protocols and registration program. CARB should consider these CAR offsets as part of a pre-compliance offsets pool which can be quickly approved to meet the CARB offsets project design criteria (available in December 2010).

- CARB should provide for early approval for linkage to other cap and trade programs, with a focus on Western Climate Initiative ("WCI") jurisdictions. CARB is already familiar with the offset program parameters and should be able to easily harmonize them with the California Cap and Trade program once the WCI finalizes its regulatory approach. Linkage with the WCI program should be easily and quickly brought to the Board and approved.

- CARB should create a specific framework for approving offset credits from individual projects that meet CARB's criteria. CARB should establish a framework for evaluating and accepting additional, individual projects outside of the sector-based projects. New technological approaches are being developed and new companies are being established to create offsets, which should have a direct pathway to approval. (SCE1)

Response: In developing the regulation, we attempted to strike a balance between creating a program that ensures the integrity of the greenhouse gas emission reductions required to meet AB 32 and one that is not overly complex. The regulation was modified to defer the compliance obligation requirements until 2013 to ensure all necessary elements are in place and fully functional. This will allow additional time to establish the necessary requirements for developing offsets in the cap-and-trade program.

We will continue to evaluate whether the four project types already approved for use in the program could be expanded to apply to projects located in the United States, U.S territories, Canada, and Mexico. Any changes to the already adopted protocols will be done as part of a separate rulemaking process to ensure that the GHG reductions and GHG removal enhancements being credited as offsets are real, additional, quantifiable, permanent, verifiable, and enforceable.

The regulation includes provisions to allow early action offset credits to be credited as ARB offset credits and used in the cap-and-trade program. We included these provisions to allow parties to develop offset projects and purchase offset credits that are being issued by Early Action Offset Programs. These provisions were added to provide parities the opportunity to participate in the offsets market while ARB is finalizing the regulation and taking the necessary implementation steps needed to have a fully functioning ARB offsets program and offsets tracking system. Once ARB Compliance Offset Protocols are finalized in October 2011, project developers will be able to use them to quantify, monitor, and report their GHG reductions and GHG removal enhancements. In 2012, ARB will be approving Offset Project Registries so that project developers can list and report their emissions with these registries, and will be accrediting

ARB offset verifiers to verify GHG reductions and GHG removal enhancements from offset projects developed under Compliance Offset Protocols.

M-45. Comment: To ensure investor confidence and thereby to bolster adequate investment in offset projects before the program begins, Evolution recommends ARB release a "priority list" of project types which the ARB has preliminary applied the criteria to and which the ARB intends to accept for compliance purposes. (EVMKTS)

Response: We recognize stakeholder concerns regarding offset supply. ARB is prohibited from adopting additional protocols as part of this cap-and-trade rulemaking. All offset protocols used in the compliance program must be adopted by the Board after undergoing a full regulatory process, including an ARB stakeholder process, in accordance with the Administrative Procedure Act, and an environmental review. We plan to look at further offset protocols for potential inclusion in the cap-and-trade program beginning in 2012. The details surrounding any new offset project types for which ARB adopts an offset protocol will be dealt with under that specific rulemaking, and modification will be made to the cap-and-trade regulation as needed.

We cannot presume which offset protocols the Board will adopt, or the outcome of any public stakeholder and regulatory process. However, we will provide period public statements in coordination with WCI of protocols that will be considered for evaluation and inclusion in the program.

M-46. (multiple comments)
Comment: While the requirements and expectation on emissions reductions projects with regard to additionality, project baseline calculation, leakage accounting, uncertainty accounting, permanence, crediting periods, and verification are reasonably clear, the mechanism and timing for agency consideration of submitted protocols and data transfer provisions are not sufficiently clear. (EDF1)

Comment: CERP asks that ARB establish a transparent process for protocol consideration, so that stakeholders can provide input. Offset project developers and investors have useful and important real-world experience to offer, and can help ensure that the offset protocols adopted by ARB will be effective, usable, and environmentally rigorous. CERP asks that ARB make publicly known which protocols are under consideration and the mechanics of the protocol consideration process. This transparency will help provide predictability for the marketplace and ensure a stable offset supply. (CERP1)

Comment: Provide more details about how and what additional protocols may be approved and how they might be approved. The draft regulation does not create enough certainty for offset project operators and investors to initiate protocols that fall outside of the scope of the four offset protocols indicated by the regulation as being "pre-approved." This will significantly slow momentum on any other offset protocols. (VCS)

Comment: CARB should develop additional, stand alone, guidance documents that clearly spell out the process that interested entities should use to submit completed protocols for consideration in the program. (EDF1)

> **Response:** All offset protocols used in the compliance program must be adopted by the Board after undergoing a full regulatory process, including an ARB stakeholder process, in accordance with the Administrative Procedure Act, and an environmental review. We plan to look at further offset protocols for potential inclusion in the cap-and-trade program beginning in 2012. The details surrounding any new offset project types for which ARB adopts an offset protocol will be dealt with under that specific rulemaking, and modification will be made to the cap-and-trade regulation as needed.
>
> Because reviewing every offset protocol submittal by potential developers would be too administratively burdensome, we did not include provisions in the regulation to establish an official protocol submittal and review process. However, we met with protocol developers over several years regarding protocols that are being developed for offset projects. We encourage stakeholders to engage with staff regarding the development of new protocols.

M-47. Comment: We also recommend that CARB establish a mechanism by which project developers, technology providers, and market participants can propose methodologies for new offset project types directly to CARB for adoption as eligible offsets for the California carbon market. While we commend the good work of the Climate Action Reserve in developing an initial set of protocols for a number of offset project types, we believe the market would be best served if developers and stakeholders can directly propose new methodologies and protocols to CARB for adoption, as this will spur maximum creativity and effort in the search for new abatement technologies and strategies. We note that over its short lifetime, the Kyoto Protocol's Clean Development Mechanism (CDM) has lead to the development of hundreds of proposed project methodologies across the spectrum of project types, leading to a considerable amount of intelligence on abatement projects built up in the CDM. The CDM methodology approval process is structured in such an open submission format and has thus harnessed the entrepreneurial energy of the market in developing new abatement technologies and project types. This may well be the biggest legacy of the CDM beyond the volume of tons abated by that particular mechanism, and we encourage CARB to consider improving upon this model in developing its own process for adopting new offset protocols. (CLIMATEWEDGE)

> **Response:** A protocol does not have to go through a voluntary registry to be approved by ARB. Because reviewing every offset protocol submittal by potential developers would be too administratively burdensome, we did not include provisions in the regulation to establish an official protocol submittal and review process. However, we met with protocol developers over several years regarding protocols that are being developed for offset projects. ARB

encourages stakeholders to engage with staff regarding the development of new protocols.

M-48. Comment: Add the following language to the end of the current provision on Procedures for Approval of Compliance Offset Protocols: "and protocols related to standards from other jurisdictions, such as the Voluntary Carbon Standards or the American Carbon Registry" (section 95971). (CALERACORP)

Response: We did not make this change. We cannot presume which organizations or offset protocols will be approved or the outcome of any public stakeholder and regulatory process in any future rulemakings. Therefore, we believe this language is inappropriate.

M-49. Comment: The process for proposing and approving offset protocols is not clearly specified and it is not clear whether going forward CARB will only accept standardized approaches or if it is open to project-based approaches. (VCS)

Response: Because reviewing every offset protocol submittal by potential developers would be too administratively burdensome, we did not include provisions in the regulation to establish an official protocol submittal and review process. However, we have been meeting with protocol developers for several years regarding protocols that are being developed for offset projects. We encourage stakeholders to engage with staff regarding the development of new protocols. We clarified the language referring to standardized methods in the regulation in new section 95972(a)(9). This should alleviate stakeholder confusion in this area. Furthermore, we are not planning on accepting project-based protocols because each protocol must be approved by the Board and such a process would be onerous and administratively burdensome.

M-50. Comment: CARB should consider outlining clear criteria, guidelines, and procedures for the evaluation and adoption of new protocols and project types to give the market clear guidance to continue developing protocols (and projects) that will provide the offsets necessary for effective cost-abatement. (VCS)

Response: Section 95972 in the regulation establishes clear criteria as to what must be included in Compliance Offset Protocols.

The Board must adopt all offset protocols used in the compliance program after undergoing a full regulatory process, including an ARB stakeholder process, in accordance with the Administrative Procedure Act, and an environmental review. We plan to look at further offset protocols for potential inclusion in the cap-and-trade program beginning in 2012. The details surrounding any new offset project types for which ARB adopts an offset protocol will be dealt with under that specific rulemaking, and modification will be made to the cap-and-trade regulation as needed.

Generally, we do not include implementation-related procedures in our regulations. We will develop guidance documents as necessary in 2012 regarding specific aspects of the offsets program.

M-51. Comment: ARB must be more aggressive in promoting the use of offsets by reducing the prescriptive details of the offset protocol approval process. (WSPA1, WSPA2)

Response: We disagree. The process outlined in the regulation is necessary to ensure the integrity of the program.

M-52. Comment: In the Scoping Plan, ARB determined agricultural emission reductions were not easily quantified. While we disagree with that assessment, if ARB feels agricultural emissions are not easily quantified or verified for purposes of direct regulations than they are similarly inappropriate as offsets. (CVAQC)

Response: In the proposed regulation, the only offset protocol related to agriculture that is recommended when the program is launched is livestock (originally referred to as "livestock manure digesters"). As the program evolves, ARB, along with our WCI partners, expect to consider additional offset protocols in a separate rulemaking.

M-53. Comment: For agricultural offset credits to provide real incentives for agricultural conservation practices that provide reductions in GHG emissions, farmers and ranchers must receive the greatest benefit possible. Currently, the carbon offset market is largely unregulated and farmers and ranchers may find themselves entering into offset credit contracts that do not adequately compensate them for their change in agricultural practices. Third party offset credit aggregators must be regulated to provide a fair share of the credit value to the producers providing the emissions reductions. To that end, CARB should establish contracting rules for offset credits that provide transparency and allow farmers and ranchers to compare contract terms across third-party aggregators. (CACAN1, CACAN2)

Response: ARB is prohibited from adopting additional protocols as part of this cap-and-trade rulemaking. All offset protocols used in the compliance program must be adopted by the Board after undergoing a full regulatory process, including an ARB stakeholder process, in accordance with the Administrative Procedure Act. We plan to look at further offset protocols for potential inclusion in the cap-and-trade program beginning in 2012. The details surrounding any new offset project types for which ARB adopts an offset protocol will be dealt with under that specific rulemaking, and modification will be made to the cap-and-trade regulation as needed. Furthermore, ARB will not get involved in third-party contracting mechanisms and would look to the market to develop standardized contracts as needed. With regard to ranchers and farmers receiving adequate compensation for their offset projects, ARB does not control prices. Rather, offset credits will be bought and sold in the market place. Prices for offset credits will rise and fall based on the supply and demand in the market.

M-54. Comment: We remain concerned about the level of offsets in the program. And now that things have changed a little bit from the Scoping Plan, there's actually a bigger bucket of offsets that could be allowed to be used. We are worried that there will be a lot of political pressure in the coming months and year to accept new protocols that may not be as stringent quality-wise so that we can fill that bucket. We want to make sure that you are able to put in place a very robust public process for vetting those protocols and making sure that they're strict in the future, and to make sure that CARB maintains a very strong role vis-a-vis the third-party registries in terms of approving and having the ability to deny in overseeing the offsets program. (UCS5)

Response: We agree that that all new protocols allowed to be used in the program need to be of the highest quality. To ensure this, all offset protocols used in the compliance program must be adopted by the Board after undergoing a full regulatory process, including an ARB stakeholder process, in accordance with the Administrative Procedure Act, and an environmental review. We plan to look at further offset protocols for potential inclusion in the cap-and-trade program beginning in 2012. The details surrounding any new offset project types for which ARB adopts an offset protocol will be dealt with under that specific rulemaking, and modification will be made to the cap-and-trade regulation as needed.

M-55. Comment: Appendix G to the Initial Statement of Reasons (ISOR) for the Cap and Trade Regulation notes (at G-16) that "if an allowance reserve of 100 million metric tons is created, at a 2020 allowance price of $25 the demand for offsets may exceed supply by 54 percent under the Appendix N supply assumptions." Table G-2 in ISOR Appendix G indicates that if the allowance reserve is 150 million metric tons, at a $25 allowance price the demand for offsets will exceed supply by 91 percent (under the Appendix N offset supply assumptions). Although offset supply is uncertain, Appendix G notes (at G-15) that the "restrictive" supply assumptions in Appendix N are likely to be indicative of conditions during the early years of the cap and trade program. (SCPPA2)

Response: No response necessary.

M-56. (multiple comments)
Comment: CARB should encourage the development of a methodology to verify third-party emissions reductions achieved within capped sectors. EDF also recommends that CARB include placeholder language, perhaps creating section 95998 (Reserved for Third-Party Crediting of Capped Sector Reductions) or a program to credit third party reductions once they are verified. (EDF1)

Comment: We urge you to rapidly develop additional protocols for generating greenhouse gas reduction credits associated with waste diversion, waste to energy, and waste recycling activities. One example is the low carbon fuel standard. (WM2)

Comment: WM supports efforts of CARB to ensure that CO_2 emissions from biomass energy and fuels are considered “carbon neutral”, particularly when the biomass fuel is waste derived. WM urges ARB to continue in this vein and provide recognition of the GHG lifecycle benefits of converting waste materials and resources into recovered materials and renewable energy. As mentioned above, WM and Linde are currently producing the lowest carbon fuel available in California at our Altamont Landfill Gas to LNG facility. Further development of waste derived fuels and energy will lead to even further reductions in GHG emissions. The Cap and Trade regulations must be structured to encourage the further development of waste derived energy and renewable resources. WM urges the CARB to develop protocols for generating GHG reduction credits for the production of waste-derived renewable resources, recyclables, energy and fuels. (WM1)

Comment: Constellation Energy urges staff’s recommendation for the potential of avoided emissions from energy-from-waste facilities and biomass (if determined to be a waste by EPA definition change) be assessed using criteria appropriate for offset projects in a formal process with opportunity for public consultation. These energy-from-waste and biomass facilities reduce emissions from uncapped sectors. Constellation Energy notes with approval that staff is of the opinion that energy-from- waste and biomass facilities should be given credit for avoided emissions that would otherwise result from alternative waste management practices, such as landfilling and open burning. (CONSTELLATIONENERGY)

Comment: The Central Valley Air Quality (CVAQ) Coalition offers the following recommendations: Biomass and agriculture as a source of offsets. As proposed, exempted categories include direct combustion of several sources of cellulosic biomass, including solid waste, construction and manufacturing debris, mill residues, range land maintenance residues, all agricultural crops or waste, and wood or wood waste. Covered entities must report emissions from the combustion of these fuels but are not required to obtain allowances for those emissions. Furthermore, neither users nor suppliers of biomass for energy are required to identify the sources of biomass material or report the biological greenhouse gas impacts associated with the removal of biomass for energy or fuel. Exempting these categories from compliance obligations is the equivalent to assuming an identical flux of carbon into and out of the atmosphere associated with all biomass growth, harvest, production, and combustion. In effect, by exempting bioenergy, the rule assumes "carbon neutrality" for all biomass fuels, which is not scientifically accurate. (CVAQC)

Comment: There are very limited opportunities in the current draft of Cap and Trade for a facility to earn offset credits. In considering our strategy to comply with AB 32, we are surprised at how few options there are for generating GHG offsets under the draft Cap and Trade Program. For example, if the District were to shut down our current CHP facility, we would reduce our anthropogenic GHG emissions by approximately 19,000 MT CO_2e. Under the current draft of the Cap and Trade Program, this GHG emission reduction would not be eligible for offset credits, because there is not an approved offset protocol for this situation. So, we are provided with no incentive to eliminate this combustion source, which would be one of the ways for CCCSD to comply with AB 32. (CCCSD)

Comment: CARB should take steps to increase the use of insulation in retrofitting existing buildings in order both to save energy and reduce emissions. An important part of this is to encourage the use of energy efficiency-based carbon offsets, which would not only help businesses in the Cap and Trade system reduce their compliance costs, such efficiency-based offsets would also have many sought-after co-benefits such as improvements in public health, increased health and safety of building and home occupants, increased home value, and reductions in other pollutants beyond greenhouse gas emissions. In short, NAIMA requests that CARB make NAIMA members' California plants part of the solution and not unfairly chase fiber glass insulation production to nearby out-of-state plants employing out-of-state workers. (NAIMA)

Comment: CARB recognized in the Scoping Plan that increasing the energy efficiency of existing buildings provides the "greatest potential for GHG reductions in the building sector." CARB's Scoping Plan urges "adopting mechanisms to encourage and require retrofits for existing buildings that do not meet minimum standards of performance." NAIMA urges CARB to broaden its scope of acceptable offsets. Energy efficiency offsets should be added to the list of acceptable/approved offsets. Insulation can be a key resource for combating climate change. Energy efficiency measures should be given top priority over renewable, where benefits tend to be uncertain, distant, and unpredictable. (NAIMA)

Comment: CALSEIA also encourages the Air Resources Board to allow distributed solar-thermal projects that are installed voluntarily (that is, at the facilities of business entities not covered by the Cap and Trade regulation) to become sources of offset credits. Example applications of distributed solar-thermal technology not already recognized as programmatic energy efficiency or renewable energy measures include residential space heating and cooling, residential solar water heating displacing propane, commercial swimming pool heating, and Industrial process heating, process cooling, and electricity generation. CALSEIA supports the Air Resources Board's efforts to develop "Compliance Offset Protocols" for voluntary greenhouse gas emission-reducing projects. Furthermore, CALSEIA requests that the Board direct its staff to work with CALSEIA to determine whether a "Compliance Offset Protocol" could be developed for distributed solar-thermal applications, such as those listed above. (CALSEIA)

> **Response:** In the cap-and-trade program, offset credits cannot be generated for activities that reduce emissions in capped sectors. If ARB were to also issue offset credits for those reductions, the reductions would be double-counted within the cap-and-trade program. Therefore, offset credits can only be issued for activities that are not capped.

For entities subject to the cap, any reduction in carbon emissions will require them to hold fewer allowances to cover their emissions and help them meet their compliance obligation.

M-57. Comment: It would be beneficial to have a mechanism for entities that took early action through energy efficiency or energy reduction projects to receive credit for these activities. Two possibilities are to allow third party verification of the specific project(s) or to allow the source to benchmark in a timeframe prior to the emissions reductions. Improving energy efficiency or reducing energy usage is more accessible for implementation for many facilities than those identified in the Livestock, Urban Forest, Ozone Depleting Substance, and Forest Protocols. (SVM)

Response: Offset credits cannot be generated for activities that reduce emissions in capped sectors. Because the electricity sector is under the cap, any reductions achieved by an individual facility would result in that facility having to surrender fewer GHG allowances. If ARB were to also issue offset credits for those reductions, the reductions would be double-counted within the cap-and-trade program. Therefore, offset credits can only be issued for sources that are not capped. Entities that are capped and took early actions are rewarded for being more efficient through design of the benchmarks for each sector.

M-58. Comment: We encourage ARB staff to seriously consider the unique role that the state's water and wastewater agencies can play in the immediate development and implementation of distributive generation renewable energy projects (including combined heat and power) and how this could support early successful implementation of the cap and trade program. The key issue is the types of projects to use and rejected the addition of an option for using verifiable on-site CAR was correct that there is a need for "plug number" formula as the starting point or baseline for the calculation of offset values. But it failed to recognize the long term value to California's cap and trade system of strengthening the data on which offset calculations are based. Entities which invest in on-the-ground measurements that show improved performance over the default numbers should be allowed to use this information to calculate their offsets. Being rewarded for making this additional investment is appropriate and will have ancillary benefits as other air quality issues, such as improvements in criteria pollutant emissions, are likely to be identified as well. (IEUA)

Response: Offset credits cannot be generated for activities that reduce emissions in capped activities. Because the electricity sector is under the cap, any activities that reduce electricity emissions would result in covered entities having to surrender fewer GHG allowances. If ARB were to also issue offset credits for those reductions, the reductions would be double-counted within the cap-and-trade program. Therefore, offset credits can only be issued for activities that are not capped.

One activity that may be viable and is not a capped activity in this sector is the reduction of methane emissions from treatment of wastewater. The potential of this project type is being evaluated by ARB staff.

M-59. Comment: The comments contained in this letter encourage CARB to include the use of supplementary cementitious materials in concrete production as a source of offsets recognized and encouraged by the program as it is implemented after adoption.

Several approaches could be undertaken to establish and verify offsets related to SCM use in concrete production. These include:

- Facility Approach. This approach would focus on the small universe of cement producers and incentivize them to blend SCMs into the finished cement products they deliver to the marketplace. There are a number of disadvantages to this approach, however. Blended cements account for only a small fraction of overall cement sales in the United States, meaning that the opportunity for incentivizing increased cement displacement in forms of concrete production not utilizing blended cements would be lost. A facility approach based on encouraging pre-blended cements would discourage concrete producer innovation in seeking higher rates of cement displacement than are possible at a cement production facility. Finally, cement producers are not able by themselves to document and verify the uses of their product after it is delivered to a concrete producer.
- Project Approach. This approach would focus on documenting offsets on a project by project basis. This approach overcomes the verification shortcomings of a facility approach, but still fails to incentivize the broadest possible use of SCMs. Transaction costs associated with establishing offsets on a project by project basis would ensure that only the largest projects are included, leaving behind the potential of incentivizing higher cement displacement in many thousands of small projects such as residential building foundations, sidewalks, driveways, etc.
- Point of Substitution Approach. This approach would establish offset creation at the point at which an SCM physically displaces a quantity of cement. It would be coupled with the existing delivery documentation that already verifies the addition and amount of SCMs added to concrete mixes subject to established weight and measures regulations. This approach creates regulatory accountability by linking reduction quantification to verification of actual utilization using a single consistent method. Under a point of substitution approach, numerous parties would be incentivized to reduce cement consumption by substituting SCMs. For instance:
  - Cement manufacturers producing blended cements would still qualify as the point of substitution for those products. Instead of capturing these reductions as increases in efficiency at the cement manufacturing plant, the cement manufacturers would more accurately capture the gains as offsets under the point of substitution methodology. This methodology would require them to coordinate with customers to document and verify the final use of the blended

cements to ensure regulatory accountability and avoid any opportunity for double counting.

- o Many cement manufacturers are also vertically integrated—owning their own concrete production facilities. A point of substitution approach to establishing and verifying offsets would allow them to capture offsets at this stage of their operations.
- o The full range of other concrete producers would also be incentivized to increase cement replacement with SCMs by following a single, consistent methodology.
- o Establishing and verifying emissions reduction offsets for concrete production at the point of SCM substitution best ensures regulatory accountability and best encourages achievement of the public policy goal of reducing greenhouse gas emissions. A point of substitution approach will encourage greater SCM utilization in every concrete production activity, whether it involves only a few cubic yards of concrete or hundreds of thousands of cubic yards. The undersigned companies support the proposed regulation's requirement that emissions reductions used to create offset credits are real, permanent, verifiable, enforceable, quantifiable, and additional. The companies intend to pursue development of a specific offset protocol to be accepted into the compliance offsets program as allowed under the proposed regulation. (BODEGRAVEL)

Response: The commenter states that the above-described activities will result in efficiency gains at the cement facility. In the cap-and-trade program, offset credits cannot be generated for activities that reduce emissions in capped sectors. If ARB were to also issue offset credits for those reductions, the reductions would be double-counted within the cap-and-trade program. Therefore, offset credits can only be issued for activities that are not capped.

For entities subject to the cap, any reduction in carbon emissions will require them to hold fewer allowances to cover their emissions and help them meet their compliance obligation.

In addition, the commenter states that the above-described activities will lower the carbon intensity of the cement produced. These emission reductions will be realized when the actual cement is produced, and may not reduce the actual emissions at the facility.

M-60. Comment: The Initial Statement of Reasons (Staff Report, Part I) discusses the potential need for ARB to work with developers to increase the supply of offset projects. It is not clear how ARB will do this, though we presume they would use future auction revenues. CAL FIRE suggests that the regulations include enabling language for working with and providing funding from auction revenues, as appropriate, to CAL FIRE which already has expertise, experience and program authorities for working with stakeholders and forest landowners. These resources could be used to incentivize the development of additional forest offset projects. If public funds were used, it might be appropriate to retire those credits, rather than trade them, or to consider their use completely outside the Cap and Trade program. If auction revenues are used to fund grant or cost-share programs that produce carbon offset projects on private lands, it may be appropriate to pro-rate the number of credits that the operator can sell to reflect the proportion of private funds used to develop the project. (DFFP1)

> **Response:** The commenter's interpretation of the language in the Staff Report is incorrect. We believe the reference that the commenter is referring to is on page II-46 of the Staff Report, Part I. In this paragraph, staff is referring to working with Offset Project Registries that will be approved by ARB to administer certain parts of the offset credit creation process. Offset Project Registries will be approved based on criteria in the regulation, and will assist new projects developed under ARB's Compliance Offset Protocols with the listing, monitoring, reporting, and verification processes for ultimate issuance of ARB offset credits by ARB. This particular text in the Staff Report is not intended to mean that ARB will work with offset project developers or financially assist the development of offset projects themselves.

Linkage

M-61. (multiple comments)
Comment: In addition to expanding CAR offsets and criteria, state officials must consider how to practically link with external offset and allowance programs, including the Western Climate Initiative (WCI), the Regional Greenhouse Gas Initiative (RGGI), Clean Development Mechanism (CDM), and EU ETS. In addition, IETA strongly supports ARB's consideration of Reduced Emissions from Deforestation & Degradation (REDD) credits into its state program. (IETA1)

Comment: The Council also recommends that California work together with the RGGI states to ensure consistency among offset programs where appropriate. (BCFSE)

Comment: SCPPA raises the following points to help ensure ARB's offset protocols and links to other offset programs provide ample cost-effective emission reduction options:

- Linking to the CDM and other rigorous offset programs should be considered in 2011. The CDM constitutes the largest, best developed, most liquid, and most scrutinized offset program in the world. It will be an invaluable source of supply, particularly in the early years of the cap and trade program when offsets from ARB protocols and from avoided deforestation ("Reducing Emissions from Deforestation and forest Degradation" or "REDD") are unlikely to be available in any quantity.
- The Cap and Trade Regulation restricts offsets from external programs to early-action CRTs, sector-based offsets and offsets issued under linked cap and trade programs. There is no provision to recognize offsets from other types of external

offset programs such as the CDM, the Voluntary Carbon Standard, or the Gold Standard. These are well-regarded international offset programs.

Linking to the CDM and other offset programs should be pursued. This will provide certainty and stimulate the development of additional offset projects. (SCPPA2)

Comment: California businesses will need access to a pool of verifiable offsets and allowances starting in 2012. Developing a new ARB offset review and approval process to review credits and allowances for use in California that have already been reviewed in the EU is costly and unnecessary. The EU carbon markets produce robust offsets and allowances. Linking to the EU would ensure a supply of high-quality and tradable market instruments for California's carbon market. Relying on a limited market Cap and Trade program to reduce emissions in California without linkage to a broad liquid market loses the economic efficiency of the market-based approach and undermines the policy goals. CCEEB recommends expediting linkage and making it a priority to be completed. If linkage is not possible, then CCEEB believes that other cost-containments measures must be adopted to soften the economic impact of this regulation and limit leakage of jobs and emissions. (CCEEB1, CCEEB2)

Comment: There are no valid scientific justifications for discriminating among ETS programs based on the source of emissions as long as the overall program meets the environmental integrity standards and other linkage criteria for an ETS established by CARB. (EDF1)

Response: The regulation includes a framework for California to link its cap-and-trade program to other emissions trading systems of similar scope and rigor. Linkage can expand the coverage of the cap-and-trade program to include emissions-reduction opportunities for sources covered in another program. The regulation does not currently include linkage to other programs, though staff anticipates bringing recommendations to the Board in 2012 for possible linkage with the programs being developed by the three other WCI Partners that are currently working to implement programs: British Columbia, Quebec, and Ontario.

Each program will undergo a case-by-case analysis by staff as part of a formal rulemaking process, and the Board will need to approve regulatory amendments reflecting the linkage with a particular program before it can take effect.

Offset Project Registries

General Offset Project Registry Comments

M-62. Comment: As currently drafted, the respective roles of ARB and “Offset Project Registry” (as that term is defined in the proposed regulation) are not clearly and precisely defined. For instance, as currently drafted, the proposed rule alternately refers to “ARB Offset Credits”, “ARB offset credits”, “Offset credits”, and “offset credits” as terms that are sometimes used interchangeably and sometimes used to indicate distinct and separate meanings. (CCAP1)

> **Response:** The regulation was modified to distinguish between an ARB offset credit and a registry offset credit, and to establish the requirements that each must meet (section 95970). Both terms are defined in section 95802, and the terms are now used consistently throughout the regulation. Offset Project Registries issue registry offset credits that meet the requirements of section 95980 pursuant to the process described in section 95980.1. ARB will review all of the documentation related to the issuance of the registry offset credits and make a determination as to whether ARB offset credits that meet the requirements of section 95981 should be issued for the registry offset credits pursuant to the process described in section 95981.1.

M-63. Comment: ARB must be more aggressive in promoting the use of offsets by focusing on approving independent offset approval agencies to reduce bottlenecks and increase the supply of offsets. (WSPA1, WSPA2)

> **Response:** ARB has provided a role for Offset Project Registries (OPR) to perform some of the administrative functions of the offset process in the regulation. ARB plans to utilize OPRs in lieu of performing these duties itself in the short-term, and may choose to continue this throughout the program. ARB has not yet determined if and when it would itself perform these roles. Therefore, in the meantime, all parties seeking to use Compliance Offset Protocols must go directly to an OPR to list their projects. ARB plans to approve OPRs sometime in 2012.

M-64. (multiple comments)
Comment: Establish offset registry as soon as possible. In order to ensure that Early Action Credits can be issued, tracked, monitored and transferred amongst market participants, it is imperative to have a functioning registry for offsets. Evolution Markets believes ARB should by Q2 2011 establish the legal agreements and necessary infrastructure support to enable an External Offset Registry, as defined by the Proposed Final Regulation. This will ensure that market participants can continue to buy and sell credits thereby supporting market confidence and easing contracting for delivery of credits. This will reduce potentially redundant transaction costs thereby reducing overall compliance costs, and will further support market liquidity. (EVMKTS)

Comment: CARB should expeditiously approve external offset registries to issue offsets that use CARB-approved protocols and follow regulatory requirements. An existing third-party organization with experience in offsets supply management (including establishment of protocols, development of projects, reductions verifications, and credits documentation) would provide immediate resources to help implement key elements of CARB’s overall offsets program, while operating under the agency’s authority. The CAR is one example; other entities may also be qualified to serve in this role. These external offset registries should be put in place in early 2011. In order to ensure an adequate supply of offsets at the beginning of the first compliance period, CARB should create a preparatory program that includes establishment of CARB-approved registries, certification of sufficient verifiers to check offset credits, and a schedule with a list of major procedural tasks with completion dates scheduled prior to January of 2012. (SCE1)

> **Response:** We agree that approving Offset Project Registries (OPR) should be done as soon as possible. ARB has provided a role for OPR to perform some of the administrative functions of the offset process in the regulation. We plan to utilize OPRs in lieu of performing these duties itself in the short-term, and may choose to continue this throughout the program. ARB has not yet determined if and when it would itself perform these roles. Therefore, in the meantime all parties seeking to use Compliance Offset Protocols must go directly to an OPR to list their projects. ARB plans to approve OPRs sometime in 2012.

M-65. Comment: Recognition of offset registries other than CAR should be expressly encouraged and the process for doing so streamlined. In addition to expanding the number of protocols for which early action credit will be granted, CARB should expand the number of registries from which early action offsets may be purchased, provided that they meet CARB standards. Several organizations, most notably VCS and ACR, have established offset registries. CARB should allow cap-and-trade participants to purchase offsets listed by those registries, as well as other registries such as the Chicago Climate Exchange. There is no reason to limit the authority to list and sell offsets, so long as the offsets are real, verifiable, additional, unique and permanent. If CARB is unable or unwilling to place those registries on the same footing as CAR by expressly recognizing them, then it should fast-track their approval via executive order under sections 95990(c) and 95986 of the regulation. Additional registries should be recognized, not only CAR. (COPC1, COPC2)

> **Response:** ARB has not yet recognized or approved any Offset Project Registries for the offsets program. In the regulation, we include provisions to accept early action offset credits issued under CAR protocols; however, ARB has not yet approved CAR as an Early Action Offset Program or Offset Project Registry. All offset protocols used in the compliance program must be adopted by the Board after undergoing a full regulatory process, including an ARB stakeholder process, in accordance with the Administrative Procedure Act. Before the Board adopts a new protocol there will be a separate CEQA review to assess the environmental impacts associated with that protocol. A public process convened by a voluntary program cannot substitute for a stakeholder process conducted by ARB for rulemaking purposes. ARB conducted a regulatory process and environmental review of the four project types adopted as part of the cap-and-trade regulation, which is why the CAR protocols associated with these four project types were approved for early action. In addition, we do not plan on only focusing on the approval of CAR-developed protocols. However, adopting additional protocols, even for early action purposes does not fall under the purview of this cap-and-trade rulemaking. If ARB were to adopt

any additional protocols that could be recognized for bringing in early action offset credits it would have to be done as part of this separate rulemaking and approval process. We will continue to work with all registries interested in the compliance offset program.

M-66. Comment: Offsets are critical to achieving cost-effective emission reductions under AB 32 especially until a broader market is developed when California links with other larger GHG cap and trade programs. While ARB has actively participated in offset creation at the Climate Action Registry (CAR), ARB has created additional prescriptive limits, and is not simply approving the protocols that they participated in. ARB has created a delegation process but is not yet delegating authority to the Climate Action Reserve to administer the offset mechanism although CAR has been very successful already in the offset development process and is a trusted entity. We are concerned that that the supply of offsets will not meet the needs of the CA Cap and Trade program and the program will cause economic harm because of the following policies and actions:

- adding additional layers of review and limits to the already difficult process of creating offsets;
- not providing any alternative review by existing and capable organizations that could serve as independent approvers of offsets; and
- adopting only four protocols.

There are existing organizations that can be approved today to address the threat of lack of supply due to bottlenecks and the overly prescriptive process. CAR can provide efficiency critical to ensuring offset supply. CAR currently has the capacity to administer the offset mechanism of the AB 32 program. Through 2009, 5.7MM credits have been issued by CAR.

We recommend that ARB designate CAR as an administrator of the offsets portion of the cap and trade system, designate non-California landfill gas CRTs as compliance-eligible offsets and include coal mine methane as an additional compliance-eligible protocol in 2011. Finally, in 2011 we would like to see direct recognition of existing offsets automatically from other established systems such as UN generated offsets and CAR approved offsets for compliance credits in California's cap and trade program, without additional administrative burden. Linking to other robust programs will promote the use of the highest quality offset credits known today and would do so in a cost effective manner. It would also help provide assurance to capped sectors and developers of offsets that a process to generate sufficient offsets is available to control costs and prevent undue economic impacts prior to full bilateral linkage with a larger cap and trade program, such as the European Union Emissions Trading Scheme. (CHEVRON1)

Response: We recognize stakeholder concerns regarding offset supply. ARB is prohibited from adopting additional protocols as part of this cap-and-trade rulemaking. All offset protocols used in the compliance program must be adopted by the Board after undergoing a full regulatory process, including an

ARB stakeholder process, in accordance with the Administrative Procedure Act, and an environmental review. We plan to look at further offset protocols for potential inclusion in the cap-and-trade program beginning in 2012. The details surrounding any new offset project types for which ARB adopts an offset protocol will be dealt with under that specific rulemaking, and modification will be made to the cap-and-trade regulation as needed.

ARB is the only agency that can regulate the offsets market. Offset Project Registries will be approved to conduct specific administrative functions of the offsets program. We may not designate one individual entity to be an Offset Project Registry and have included an application and approval process in the regulation to approve Offset Project Registries.

The regulation includes a framework for California to link its cap-and-trade program to other emissions trading systems of similar scope and rigor. Linkage can expand the coverage of the cap-and-trade program to include emissions-reduction opportunities for sources covered in another program. The regulation does not currently include linkage to other programs, though staff anticipates bringing recommendations to the Board in 2012 for possible linkage with the programs being developed by the three other WCI Partners that are currently working to implement programs by January, 2012: British Columbia, Quebec, and Ontario.

Each program will undergo a case-by-case analysis by staff as part of a formal rulemaking process, and the Board will need to approve regulatory amendments reflecting the linkage with a particular program before it can take effect.

M-67. Comment: Section 95986 uses the term "registration" and "registered" in a context that does not refer to offset credits (See for example (c), (c)(3)(A)). Given the specific use of this term to refer to offset credits in other parts of this Section, as well as other parts of the regulation, we suggest that a different term be adopted for the approval of offset project registries. (TPI2)

Response: We did not make the changes requested by the commenter because under section 95986(c) the provision refers to registration specifically identified in section 95830. Referencing the specific section here makes it clear what type of registration the provision is referring to. In section 95986(c)(3)(A), the use of the term registration is consistent with the way it is used for registering market participants because the term refers to registering parties and not offset credits.

Registry Approval Process and Requirements

M-68. Comment: Section 95986(d) requires the offset project registry applicant to have its "primary business" operate an offset project registry. This requirement may exclude GHG programs like the VCS which do much more than provide a limited registry function. To be clear, the VCSA is strictly dedicated to the management and improvement of the VCS Program and does not undertake other activities (e.g., consulting, validation/verification, methodology development) within the carbon market, and we applaud CARB's attempt to ensure that offset project registries not play larger roles in the market as that could lead to real or perceived conflicts of interest. The VCSA recommends that the language in this section be amended to include "operating a GHG program that includes a registry system." (VCS)

> **Response:** We clarified the language in section 95986(d) regarding the function of registries. If a registry becomes approved by ARB as an Offset Project Registry, they must perform specific functions designated in the regulation. The regulation allows a registry to perform different functions as part of their voluntary registry services, as long as the Offset Project Registry has the capability to perform the roles designated by ARB in sections 95986 and 95987.

M-69. Comment: In addition to recognizing external registries, the VCSA encourages CARB to consider the difference between registries and greenhouse gas programs. GHG programs encompass a broader range of offset functions than registries, which primarily serve to issue offset credits and allow participants to transfer them between accounts. GHG programs generally provide a comprehensive architecture and process by which protocols and projects are developed and approved, contain policies governing conflicts of interest, outline procedures for accreditation of validation and verification bodies, and set out details regarding eligibility of projects and other matters. Under CARB's proposed protocol system, many of the details that would normally be found under a broader program's architecture of rules are contained within the protocol's terms. In other words, in CARB's design, each protocol would be a standalone system and would contain many of the rules that govern all offset projects. In contrast, some GHG programs like the VCS operate on the basis that the high-level rules are applied to all protocols adopted under the program. The VCSA recommends that CARB consider this difference in approach when considering recognition of external protocols. If each protocol contains many of the same rules that are contained in all protocols, whenever a high-level policy change is made, for instance, governing how many crediting periods a project is eligible to renew, amendments will have to be made to each protocol that has been recognized, potentially creating a significant added workload that could be minimized if the generally applicable rules are contained at a higher program level that universally applies to all protocols. The VCSA offers this input as CARB seeks to potentially integrate registries and protocols from greenhouse gas programs that have adopted a slightly different approach to protocol development. (VCS)

> **Response:** We clarified the language in section 95986(d) regarding the function of registries. If a registry becomes approved by ARB as an Offset Project Registry, they must perform specific functions designated in the regulation. The regulation allows a registry to perform different functions as part of their voluntary registry services, as long as the Offset Project Registry has the capability to perform the roles designated by ARB in sections 95986 and 95987.

Any protocol incorporated into the regulation, becomes a regulatory document in itself. ARB has included general requirements that apply to all protocols in the regulation and has kept protocol-specific criteria within the protocols. Any new protocols that would be accepted would need to go through a separate rulemaking process to ensure the resulting offsets meet the AB 32 criteria and the offset project requirements conform to the regulatory requirements. This new rulemaking would be an amendment to the existing regulation. As all of this is a rulemaking action, no alternative protocol development process can be substituted in its place.

M-70. (multiple comments)
Comment: Reconsider the level of liability insurance that will be required. The requirement for an offset project registry to hold $50 million in liability insurance would be prohibitive for most non-profit organizations of the type that would likely seek to become offset project registries. Moreover, an insurance policy regarding improper issuance of offset credits may even be impossible to obtain in the insurance market. In addition, it is not clear what the term of such a policy would be required, and what the coverage or trigger for the insurance would be. (VCS)

Comment: We agree that Offset Project Registries must carry liability insurance; however, currently, it is not possible for Offset Project Registries to obtain $50 million in liability insurance, as required under section 95986(c)(1)(E). The insurance industry does not typically provide liability insurance in this amount and few entities, if any, could reasonably afford such insurance if offered. Industry standard limits for liability are between $1 million and $5 million. Changing the $50 million requirement to $5 million is a realistic requirement that is possible for Offset Project Registries to meet. Further, of equal importance to the amount of coverage is the nature of that coverage. Most general or professional liability insurance policies do not specifically cover the improper issuance of offset credits or other similar commodities, yet this is precisely the risk the Air Resources Board is seeking to manage. We would strongly suggest that the Air Resources Board impose requirements that the required liability insurance specifically cover the issuance of offset credits. (CAR1)

Response: We agree and modified the regulation to require a level of professional liability insurance of $5 million instead of $50 million. We have spoken with potential Offset Project Registries regarding this level of insurance and believe that Offset Project Registries will be able to secure an insurance policy at this level.

M-71. Comment: CERP supports the use of approved offset project registries for project listing, verification oversight, and credit issuance—in combination with an expedited, transparent process for exchanging registry-issued credits for ARB-issued credits. CERP also supports the use of ARB- approved verifiers to meet AB 32's requirement for ARB oversight of verification. There are, however, certain aspects of the offset project registry mechanism that might prove problematic. The five year approval period for offset project registries creates too much insecurity for projects registered at approved registries. ARB should provide greater certainty for registered projects. The proposed regulations provide that an offset project registry could be approved to participate in the ARB program for five years, subject to renewal. This five year approval period, which is shorter than any project's crediting period, will create considerable uncertainty for offset projects registered with those registries, and therefore limit the registries' appeal and utility. CERP recommends that ARB provide an accelerated process by which projects registered with a registry that becomes "un-approved" can re-register with ARB, and continue any on-going crediting period. CERP also recommends that ARB clarify that the validity of already-issued credits will not be compromised if the issuer-registry does not secure a subsequent approval from ARB. (CERP1)

> **Response:** We changed the approval period for Offset Project Registries from five years to 10 years to address stakeholder concerns that five years was too short. In addition, in new section 95986(l)(3) we added provisions to allow offset projects that must switch registries due to "un-approval" to qualify for an extended crediting period of one year.

M-72. Comment: Reconsider the re-application requirement. CARB should not require external offset project registries to re-apply for registration every five years (section 95986(i)(5)). This is unnecessary particularly in light of CARB's ability to sanction an offset project registry for misdeeds under section 95986(j). It also creates significant uncertainty for projects registering under an external offset project registry where those projects have crediting periods longer than five years. This uncertainty would serve as another disincentive to use an external offset project registry as opposed to CARB's offset project registry. (VCS)

> **Response:** We changed the approval period for Offset Project Registries from five years to 10 years to address stakeholder concerns that five years was too short. Original section 95986(j), now section 95986(l), was modified to clarify what happens to offset projects that reside at an Offset Project Registry, whose approval has been suspended or revoked. These offset projects may transfer to another approved registry and continue its current crediting period. In addition, in new section 95986(l)(3) we added provisions to allow offset projects that must switch registries due to "un-approval" to qualify for an extended crediting period of one year.

M-73. Comment: We are pleased with and support the accreditation of third-party Offset Project Registries to assist with program implementation. We strongly believe that it is imperative for the Regulation to impose strict competency requirements for such registries. Offset registry services are complex and require specialized knowledge and experience, especially when providing guidance to offset project operators and verifiers on protocol requirements (as contained in section 95987(d) "The Offset Project Registry may provide guidance to Offset Project Operators"). In order for this guidance to be accurate, timely, and consistent, Offset Project Registries should be required to demonstrate deep competency in each protocol they seek to administer to avoid programmatic errors and market confusion. (CAR1, CAR2)

> **Response:** The regulation requires that ARB will only approve registries that meet a high standard under the regulation. The registry staff will be required to demonstrate practical knowledge of the protocols approved by the Board. The regulation contains requirements for regular information-sharing between the registries and ARB. The regulation allows for ARB to request information or discussions with registry staff at any point. As with many of ARB's regulations, compliance training will be available, and in this case required, to ensure the highest qualified personnel are on staff at the registries.

Registry Services

M-74. Comment: Under the proposed regulations, ARB will be notified of all protocol guidance and interpretations provided to verifiers and offset project operators by approved registries. However, the proposed regulations do not clarify what will happen if ARB disagrees with that guidance. The proposed regulations should specify what will happen if ARB disagrees with protocol guidance or interpretation supplied by an approved registry. (CERP1)

> **Response:** Section 95987 specifies that an Offset Project Registry may seek clarity from ARB before providing guidance to offset verifiers and Offset Project Operators. In addition, the regulation requires that Offset Project Registries submit a monthly report to ARB regarding the guidance they have provided. ARB will then make this information available on a publicly accessible website, so that verifiers and project operators can consult this guidance before having to request it from the Offset Project Registry. We believe that ARB will be in constant contact with the registries and do not see there being a problem in this regard.

M-75. Comment: Clarify the mechanism for third party registries, such as the Climate Action Reserve, to provide timely, consistent and accurate responses to questions that arise during offset project development and implementation. Offset registries should be required to demonstrate substantial competence and technical depth on any offset protocols they are using. There should be an ARB-administered competency exam and/or demonstrated experience in implementing the relevant protocols. There needs to be a clear, transparent mechanism to ensure that ARB and the various Offset Registries are all aware of any guidance that is provided to Project Developers. The regulations require the Offset Registry to communicate any guidance to ARB. We suggest that the regulations require that all guidance be made available on a publically accessible web site available to any Offset Registry or member of the public. In this way, the guidance documents can begin to form a body of "case law" to help guide consistent implementation of the protocols. (PFT1, PFT2)

Response: Section 95987 specifies that an Offset Project Registry may seek clarity from ARB before providing guidance to offset verifiers and Offset Project Operators. In addition, the regulation requires that Offset Project Registries submit a monthly report to ARB regarding the guidance they have provided. ARB will then make this information available on a publicly accessible website, so that verifiers and project operators can consult this guidance before having to request it from the Offset Project Registry. We believe that ARB will be in constant contact with the registries and do not see there being a problem in this regard.

Also, the regulation ensures that ARB will only approve registries that meet a high standard under the regulation. The registry staff will be required to demonstrate practical knowledge of the protocols approved by the Board and the compliance offset program.

M-76. Comment: Both ARB and the approved third-party offset program are required to track an offset after the credit is approved by ARB. This should not impose multiple transaction fees on offset purchasers and sellers. This section requires both ARB and the approved third-party program to "track the transactions of offset credits until ARB retires" such credits. As all third-party registries will likely impose transfer fees for offset transactions, we would recommend that ARB clarify that a project will only be charged transfer fees by one registry for early action credits that have been transitioned into compliance credits by ARB. (section 95990(d)) (SHILLINGLAW1)

Response: Offset Project Registries must track registry offset credits. These credits may not be used for compliance. Once the registry offset credits are brought into the compliance system, ARB will issue ARB offset credits to replace the registry offset credits. ARB is the only entity that will track ARB offset credits; they will not be tracked in the registry's system. Once ARB issues an ARB offset credit, the Offset Project Registry must retire, remove, or cancel the original registry offset credit in its system. The offset system is set up so that no offset credit exists in two systems at the same time; therefore, the scenario laid out by the commenter should not occur.

M-77. Comment: Section 95986(c)(3)(C) requires that a registry possess a repository of ownership information of all offset credits it issues, including prices and counterparties. While it may be important for ARB to understand the transaction prices of compliance instruments, it is not important or relevant for ARB to understand or require a registry to track prices of credits which are being sold for voluntary retirement; which do not meet ARB's requirements for compliance credits; or which otherwise are unrelated to the ARB program but are nonetheless registered on a registry which has been approved by ARB. It is unclear whether ARB expects approved offset registries to shut down their voluntary programs; expects them to run parallel but separate registries; or expects them to treat all credits and recordkeeping as if they were compliance instruments even if they do not qualify or are not being transferred. Imposing regulatory recordkeeping and disclosure requirements on the voluntary market will significantly dampen this market's contribution to mitigating climate change and should be avoided. (TPI2)

> **Response:** ARB modified this language to clarify that Offset Project Registries must have these capabilities for offset credits issued under this article (under Compliance Offset Protocols). This clarification was made because the Offset Project Registries do not need to meet these requirements for offset credits that are developed for voluntary purposes.

M-78. Comment: Reconsider the project audit requirement. While it is critically important that oversight of project verifications is provided, the requirement that external offset project registries audit and physically visit 20 percent of their projects is onerous and likely to be prohibitively costly and thus limit the scalability of the mechanism. Depending on the number of projects listed in an offset project registry, it may be very difficult to coordinate scheduling of all these projects among three different entities at the same time of the year. Instead, we would recommend emphasizing oversight of the validation/verification bodies. Under the VCS Program, this is achieved through a strict and rigorous process of accreditation, combined with annual surveillance of validation/verification bodies by the accreditation body and contracts between the VCS Association and these entities that set out obligations and liabilities. The American National Standards Institute (ANSI) may be an appropriate accreditation body to provide accreditation services for CARB, especially given their long-standing expertise in this area. This would allow CARB to leverage an existing platform, scale up the number of approved auditors quickly, and provide consistency across the market, including one that already establishes links with international partners and may likely have more in the future. (VCS)

> **Response:** We agree and modified section 95987(e) of the regulation to change the number of in-person audits that Offset Project Registries must perform from 20 percent to 10 percent. We reduced the number of in-person audits because ARB will also have its audit program that will include in-person audits, in addition to those performed by Offset Project Registries. We will also have access to the audit results collected by Offset Project Registries.

M-79. (multiple comments)
Comment: No current voluntary registries have the capability to track price. (TPI2)

Comment: Remove the requirement for offset project registries to track prices and counterparties. The VCS does not track prices and does not see the value in having the offset project registries track such information. The purpose of a GHG program and its associated registry is to ensure the creation of offsets according to the criteria and rules set out in the program, and the requirement to track prices is not relevant to the work of a GHG program. (VCS)

Comment: While pricing plays a fundamental role in the market's operation, the requirement that Offset Project Registries track and report offset prices is likely unworkable as currently drafted and would effectively preclude recognition of any early action credits. Credible offset registries, including the Climate Action Reserve, have intentionally chosen to neither seek nor manage information related to pricing to avoid a real or perceived appearance of a financial interest in offset projects. Further, outside of exchange-based transactions, per unit pricing information is not always readily known or fully discoverable since transactions can be very complex and dependent on external factors. Most importantly, because this information has not been tracked for early action offset projects under the recognized offset quantification methodologies specified in section 95990(b)(5), its inclusion as a requirement would alone preclude all previously transacted offset credits under the adopted standards from being recognized as early action offsets, undermining the cap-and-trade program. (CAR1)

Comment: We recommend that the requirement for registries to record pricing information is removed. Registries do not currently maintain pricing data nor is it their role to do so. Beyond the fact that pricing data is extremely sensitive information, it is impossible for a registry to maintain per-offset data for highly structured over-the-counter contracts which may include revenue sharing, package pricing, or swaps. (NISSENBAUM)

Comment: Concerning transaction prices, we have concerns with the simplicity of this requirement when compared to the types of transactions common in the secondary compliance instrument marketplace. Forward sales, partial pre-pays, derivative such as options, the associated transaction credit and insurance requirements and other factors make determination of "price" less than straightforward. At the same time, these transactions create the capital to originate projects, increase liquidity and help limit market volatility. Also, many buyers keep prices confidential as sensitive business information; it is not clear how ARB would handle this sensitivity. Limiting price discovery to instruments already registered on the ARB registry may alleviate the complexity somewhat. (TPI2)

Comment: Third-party offset programs should not be required to track prices for offset transactions to be approved by ARB. Third-party offset programs that may apply to ARB under this section do not, as a general rule, track pricing information in offset transactions. They do not function as exchanges (such as NYSE) and are not regulated as such by the SEC; rather, their registry function tracks ownership of particular offset credits. In addition, there are practical problems associated with tracking prices of over the counter trades, which can take a myriad of forms. We would recommend deleting the last clause ("including prices and counter-parties") in this section (section 95990(c)(2)(C)). (SHILLINGLAW1)

> **Response:** We agree and modified the regulation to remove the requirement for price tracking for both Early Action Offset Programs and Offset Project Registries.

M-80. Comment: In the event that an offset project registry has contractual agreements with third parties for the provision of registry services involving the issuance of and custodial holding of offset credits, these third parties should face minimum financial asset and/or credit requirements. In addition, insolvency protections should be considered so that offset credits being held in the third party registries do not become tied up in bankruptcy proceedings. Strict conflict of interest provisions should also be imposed on these service providers. (VCS)

> **Response:** New section 95986(c)(2)(A)(3.) was added to require that conflict-of-interest and confidentiality requirements be in place for any contractors of Offset Project Registries. This new section provides additional integrity to the offset program. Offset Project Operators should conduct due diligence in selecting an offset project registry.

M-81. Comment: We recommend changing the record retention time for section 95988 to five years after the verification statement is issued, as noted above. (TPI2)

> **Response:** Section 95988 was modified to change record-retention requirements for Offset Project Registries to 15 years. This change was made to be consistent with the new record-retention requirements for Offset Project Operators and Authorized Project Designees in section 95976.

ARB vs. Offset Project Registry Roles

M-82. Comment: The language in sections 95980, 95981 and 95985 of the proposed regulation should be cross-referenced and clarified to explicitly indicate that ARB retains final authority over the issuance and invalidation of offset credits for use in the California Cap and Trade program. Providing this type of clarification will help further the transparency, accountability, legitimacy and success of the program. (CCAP1)

> **Response:** We agree and modified the regulation to clarify our authority over the issuance and invalidation of offset credits. In addition, we clarified that ARB makes the final determination on whether or not a registry offset credit meets all requirements of the regulation and added this text to the regulation.

M-83. Comment: Clarify CARB's authority as the final arbiter of offset credit and verification disputes. (ENVENTREP1)

> **Response:** We agree with the comment to more clearly define ARB's role in offset decisions. We deleted Offset Project Registries from the appeals process for adverse verification statements. This clarification was made to be consistent with the MRR and reflects stakeholder comments that the appeals process should only be limited to determinations made by the Executive Officer of ARB and that ARB should be the only one to make these determinations. In addition, we clarified that ARB makes the final determination on whether or not a registry offset credit meets all requirements of the regulation, and we added this text to the regulation.

M-84. (multiple comments)
Comment: Qualified third-party offset registries can play a valuable role in managing offset programs used for compliance with the cap. Independent private entities (either nonprofit or for-profit), however, cannot be granted ultimate authority over compliance determinations. As the regulatory agency designated by the legislature to implement AB 32, CARB must retain final authority to determine whether an offset credit submitted for compliance conforms with the established requirements under the program. The Executive Officer should be the ultimate arbiter of disputed verification reports and CARB should be given explicit authority to deny issuance of an offset credit when a project does not comply with regulatory requirements. (NRDC1)

Comment: We understand that there is a role for qualified third-party offset registries that are paid by offset developers to assist in managing the offset program used for compliance with the cap. However, because offset registries' profits are directly tied to the number of offsets that are verified and sold through their systems, this may create an incentive to make decisions that favor the offset developers they work with at the expense of the environmental integrity of the offset. Climate registries should not be put in the position of both promoting and selling offsets (their bread and butter) while at the same time regulating the offsets market. As the regulatory authority in charge of ensuring that offsets represent real emission reductions, CARB must have a clear role in key decisions regarding verification and offset acceptance or denial. For instance, in Section 95977(e)(2)(C)(xix)(a-c), solely the CARB Executive Officer should handle petitions from offset developers disputing Verification Statements, make decisions on whether the Offset Project Data report meets proper standards, and make final determinations on resolving disputes. Section 95980 should allow the CARB Executive Officer explicit authority to deny any offset proposals that the Executive Officer finds does not meet relevant offset criteria. (UCS1, WALTERS, LUDLOW)

> **Response:** ARB is the only agency that can regulate the offsets market. Offset Project Registries will be approved to conduct specific administrative functions of the offsets program. We have made clarifications to the regulation stipulating that ARB has the final decision in dispute resolution regarding verification and the final decision regarding the issuance of ARB offset credits which may be used for compliance. We have also included provisions regarding conflict-of-interest for Offset Project Registries to ensure the integrity of the program.
>
> We agree with the suggested change to delete Offset Project Registries from the appeals process for Adverse Verification statements. This clarification was made to be consistent with the MRR and reflects stakeholder comments that the appeals process should only be limited to determinations made by the Executive Officer of ARB and that ARB should be the only one to make these determinations.
>
> In addition, the regulation requires that Offset Project Registries submit a monthly report to ARB regarding the guidance they have provided to offset verifiers and project developers.

M-85. Comment: Provide more details about external offset project registries. The draft regulation does not create enough certainty for external offset project registries to incentivize them to prepare and apply to become an approved registry. In addition to the possibility that external offset project registries may have to compete with the CARB registry, the following issues are not clear:

- process for applying to be an approved external project registry;
- when the application window open;
- fees, if any, to participate; and
- restrictions on what the offset project registries can charge for the issuance of offsets that will later be issued by CARB? (VCS)

  Response: The regulation allows offset projects to come into the program directly under Compliance Offset Protocols instead of first registering with CAR and using CAR voluntary offset protocols and then transitioning over to ARB's protocols. ARB has provided a role for Offset Project Registries (OPR) to perform some of the administrative functions of the offset process in the regulation. ARB plans to utilize OPRs in lieu of performing these duties itself in the short-term, and may choose to continue this throughout the program. ARB has not yet determined if and when it would itself perform these roles. Therefore, in the meantime all parties seeking to use Compliance Offset Protocols must go directly to an OPR to list their projects. The cap-and-trade regulation must be approved by the Board and take effect before approval of an Offset Project Registry. Given this requirement, ARB plans to approve OPRs sometime in 2012.

  The process for applying to be an Offset Project Registry is specified in section 95986. There is no fee charged to apply as an Offset Project Registry; however, the registry must have five million dollars in professional liability insurance and pay the costs associated with any training. ARB will not specify what fees can be charged by Offset Project Registries for the issuance of registry offset credits. We expect this to be determined among the registry and the third-party operating the offset project or purchasing the registry offset credits. ARB will not charge a fee for the conversion of registry offset credits to ARB offset credits.

Monitoring, Reporting, and Record Retention Requirements

Timing for Providing Documents to ARB

M-86. Comment: Modify section 95976(e)(4) follows: (e)(4) - Upon request by ARB or an Offset Project Registry, ~~the Offset Project Operator or Authorized Project Designee must provide to ARB or an Offset Project Registry all documents~~ for a copy of documents that reasonably describes an identifiable document or documents retained pursuant to this section, the Offset Project Operator or Authorized Project Designee shall make the documents promptly available. The Offset Project Operator or

Authorized Project Designee, upon a request for a copy of documents, including data used to develop an Offset Project Data Report shall, within 10 calendar days from receipt of the request, determine whether the request, in whole or in part, seeks copies of documents retained pursuant to this section and shall promptly notify the person making the request of the determination and the reasons therefore. (OFFSETSWG1)

> **Response:** We did not make this change. Section 95976(e)(4) is very clear on the types of record retention required and to be made available to ARB upon request. Any delay in receiving that data could hamper all oversight of the program, and subsequent enforcement, as needed.

Interim Data Collection Procedures and Variances

M-87. Comment: Section 95976(f)(1)(A) allows Offset Project Operators to apply to ARB for interim data collection method approvals in the case of unexpected equipment failure. However, this approval mechanism is limited to incidents which may result in the loss of at least 20 percent of a project's annual emission reduction volume; another way to think about this, is that projects must be at risk of losing at least 73 days of data to be able to apply to ARB for a substitute/interim data collection procedure. We recommend that this loss threshold be lowered to eight percent, or about 30 days of data. It does not seem equitable that projects with major equipment problems have special procedures available to them while projects with lesser but still material data loss challenges do not have such rights. We believe this lower threshold better balances the workload implications for ARB with the capability of project operators to address equipment failures in a timely manner. (TPI2)

> **Response:** We did not make this change. We believe that routine inspections should allow for identification of problems that would lead to most cases of data loss. To be eligible to use this provision, the problem must be identified within 30 days of the initiation of data loss. This requires that the offset project operator develop and implement a routine inspection program for the offset project. We believe the twenty percent threshold provides a good balance between the number of requests made to ARB for interim data procedures and due diligence by the offset project developer to implement a routine project inspection program. All projects, regardless of size, should have a stringent offset project inspection program.

M-88. Comment: ARB needs to provide greater clarity on how project owners and offset project developers should obtain timely clarification on certain aspects of the protocol. (It is not clear whether qualified positive verification statements will allow verifiers to accept deviation from or slight changes to protocols as dictated under certain project specific circumstances). Currently, updates to quantification methodologies have to be made public through a public review and Board adoption process. There are likely to be numerous instances where project owners and developers require clarity on the interpretation of the guidance provided or wish to deviate from the protocol due to some unforeseen event. Waiting for public review and board approval may result in the project missing deadlines prescribed in the regulations. ARB needs to enable verifiers and/or registries to make decisions on deviations and variances within a short-time frame and to specify what constitutes a deviation or variance. (CIG)

> **Response:** As part of the implementation phase, we will be developing guidance documents for project owners, developers, and verifiers after the regulation has been approved and finalized by the Board. These guidance documents will include procedures for obtaining clarification and contacting ARB staff regarding questions on implementation as project developers and verifiers proceed with their offset projects. Updating numerical or equation-related aspect of the protocol is considered part of the protocol's quantification methods. Changes to quantification methods can be updated through stakeholder input and Board action without having to go through the full APA (Administrative Procedure Act) process. Where interpretation of quantitative methodologies is necessary, we anticipate developing a process whereby staff will release topical guidance documents. These are issues that will be addressed as part of the implementation process once the regulation is approved.
>
> In addition, the regulation does not allow for variances, since each offset protocol must be approved by the Board after a full public and regulatory process. In addition, any changes made to Compliance Offset Protocols must be approved by the Board. In the event that monitoring equipment associated with an offset project fails, the project operator may ask ARB to approve methods for interim data collection procedures.

M-89. Comment: CERP supports the potential use of qualified positive verification statements, and urges ARB to create a public database of approved variances. CERP strongly supports the use of qualified positive verification statements where nonconformance with a protocol does not result in an offset material misstatement. CERP urges ARB to collect and make public a list of "non-conformances" (or "variances") found to be valid by a verifier. Often different offset projects will encounter the same problem, and it will be more efficient if the operators and verifiers are not forced to reinvent the wheel each time. A public list of previously-approved variances will bring some order, consistency, and efficiency to the process. In addition, a public list of variances can identify the kind of recurring issues that should be considered in the process of developing a new or revised methodology. (CERP1)

> **Response:** The regulation does not allow for variances, since each offset protocol must be approved by the Board after a full public and regulatory process. In addition, any changes made to Compliance Offset Protocols must be approved by the Board. This would be onerous and too administratively burdensome. However, in the event that monitoring equipment associated with an offset project fails, the project operator may ask ARB to approve methods for interim data collection procedures.

Record Retention Requirements for Offset Project Operators and Offset Verifiers

M-90. (multiple comments)
Comment: Section 95976(e)(2) sets document retention limits relative to a project's crediting period. This creates a long and uneven, variable document retention policy. For example, much of a project's documentation results from verification and monitoring work. A project with a 10-year crediting period would be required to retain some documents for 15 years, and other documents of exactly the same type, sensitivity and implication, for only five. Variable retention policies are very difficult and relatively expensive to implement. Since the standard makes clear that five years is a sufficient timeframe to retain verification documents, we recommend that retention of all monitoring and verification records be limited to five years after the issuance of the relevant verification opinion. (TPI2)

Comment: It is not customary to transfer copies of records or documents from project owners to verifiers for periods longer than the verification itself. Many landowners see this information as highly confidential and outside knowledge could be detrimental to their business. We recommend that a verifier only be required to keep a record of what they have reviewed during the verification including version, page, volume, data base ID, etc. (NISSENBAUM)

Comment: PG&E feels that the record retention period for Offset Project Operators or Authorized Project Designees is inconsistent with the verification requirements and too long for sequestration projects. We recommend that ARB make the data retention requirements in section 95976 (e)(2) consistent with the requirements in section 95977(e)(2)(C)(xi). (PGE1)

Comment: SCPPA raises the following point to help ensure ARB's offset protocols and links to other offset programs provide ample cost-effective emission reduction options: Section 95976(e)(2) (p. A-122) requires documents for sequestration projects to be retained for 100 years after the end of the crediting period (which itself may be extremely long). Requiring records to be retained for 100 years is impractical, unenforceable, and verges on the ridiculous. Record retention and production periods should be changed. As SCPPA has noted in its comments on other sections of the Cap and Trade Regulation, a 10-year retention period is unreasonably long. By contrast, the US Environmental Protection Agency's Mandatory Reporting of Greenhouse Gases Rule ("EPA Rule"), 40 CFR Part 98, only requires records to be kept for three years. (SCPPA2)

Comment: Section 95976 of the regulation sets out record retention requirements. Clearly a sequestration project could be allowed to establish a final crediting period baseline plus all offsets credits registered and then enter a monitoring process that would not require maintenance of all the preceding decades of documents. Of course during the active crediting period these records are necessary, but once in the monitoring period, with no additional revenue cost is an important issue. (CAFORESTRYASSOC1)

Comment: The proposed record retention requirements are unnecessary and excessively burdensome. Under the proposed regulations, the offset project representative is required to maintain all of the information relevant to measuring and verifying emission reductions or sequestration for five years after the end of a crediting period for a non-sequestration project, and for 100 years beyond the end of crediting for a sequestration project. The duration of these retention requirements is, to say the least, commercially unrealistic—many corporations do not exist for 100 years. It is our understanding that the 100-year requirement may be based on a similar requirement imposed by the Climate Action Reserve. It is quite possible that the Reserve could cease to exist well before the crediting period ends for many of its listed projects. By contrast, ARB is an agency of the state government, and is tasked with regulatory oversight. It is reasonable to expect ARB to bear the burden of long-term record retention for the offset projects it oversees. CERP suggests that ARB require any information it may need in the future to be submitted to ARB at the time of verification. (CERP1)

> **Response:** The record retention requirements in section 95976(e)(2) were changed to 15 years following the issuance of ARB offset credits, due to stakeholder concerns about an unnecessarily long record-retention requirement for forestry projects. Verifiers are also required to retain related documents for 15 years. The record retention requirements must be extensive enough for verification of each Offset Project Data Report. This provision is necessary to ensure that ARB or an OPR will have enough data to confirm the crediting project has been operating in accordance with the appropriate ARB-approved protocol.

M-91. Comment: The record retention, conflict of interest requirements, and re-verification of early action offsets will discourage offset project development. Modest changes are needed to the recordkeeping requirements and the conflict of interest requirements will need to be more flexible at the start of the program. (BCFSE)

> **Response:** The record retention requirements in section 95976(e)(2) were changed to 15 years following the issuance of ARB offset credits, due to stakeholder concerns about an unnecessarily long record-retention requirement for forestry projects. Verifiers are also required to retain related documents for 15 years.
>
> Also, we do not agree that the conflict-of-interest requirements for offset projects are too restrictive. These provisions are necessary to ensure the integrity of the offsets system and to ensure that all reviews associated with the data from offset projects are unbiased and independent.
>
> We also made changes to section 95990(f) regarding the regulatory verification of early action offset credits to streamline the requirements in response to stakeholder comments.

Reporting and Verification Deadlines

M-92. (multiple comments)
Comment: Minimize unnecessary bureaucratic requirements. Provide flexibility in the frequency of verification, as appropriate [pg 124(b)] (CCEEB1)

Comment: The penalty for a late Project Data Report is too harsh given the potential for extenuating circumstances beyond the Project Operator's control. We recommend that the penalty be pro-rated using a sliding scale depending on the lateness of the report and to clarify that a delay resulting from ARB or an associated registry will not result in a penalty. (NISSENBAUM)

Comment: Prohibiting issuance of all offsets credits reported in an Offset Project Data Report due to the report being one day late is not reasonable. We would recommend graduated sanctions. Delivering an offset project data report will involve coordination and cooperation between the landowner and multiple consultants, and the report could be late for multiple reasons outside of an Offset Project Operator or Authorized Project Designee's control. We would recommend a graduated sanctions approach if it is necessary to impose sanctions for late reports, with a higher percentage of credits being deducted for each one month period a given report is late. (section 95976(e)) (SHILLINGLAW1)

Comment: The rigid due date for the Offset Project Data Report is impractical for sequestration projects. A report cannot be completed until after the end of the calendar year; however, it is possible that in some areas of the country where sequestration projects will be implemented, winter weather may impede the ability to collect the necessary data between the end of the calendar year and April 1 of the following year. We request that the date be extended to July 1 of the following year or allow sequestration projects to have an automatic extension to July 1 of the following year. (NISSENBAUM)

Comment: Section 95977(d) includes a very strict delivery date for offset verification reports. The penalty for being late is denial of eligibility of the offset credits reported in that Offset Project Data Report. This seems highly punitive especially given that many projects will have multiple years of data verified in the first report and if necessary to avoid this penalty just wait another year and submit this first Offset Project Data Report without any penalty. Especially in the first few years, such deadlines should be more flexible to allow verifiers to get up to speed and ARB to have a steady flow of offsets arriving to keep Cap and Trade economic impacts down. Section 95976 has a similar deadline and penalty for Offset Project Data Reports, which should be addressed. (CAFORESTRYASSOC1)

Comment: The requirement to report on a calendar year basis will increase costs for projects which don't begin on January 1st by requiring them to perform an additional verification and will also lead to verification bottlenecks (and likely an increase in prices for verifiers) at the start of each year. This impacts smaller projects and livestock projects in particular, which are unable to shoulder additional transaction costs, more than it does larger projects. (CIG)

Comment: We support the prompt submission of all data and reports required under ARB market rules; however, ARB should provide a mechanism for requesting extensions in appropriate circumstances. For instance, the penalty of disqualification for missing the April 1 deadline for project performance reports in section 95975(d)(7) is draconian and not compelled by the program needs. (FCC, BLUESOURCE)

Comment: The standardized verification schedule is likely to create a verification and issuance traffic jam, and should be revised. Under the proposed regulations, all ARB-eligible offset projects will be undergoing verification between April and September. We are unclear about the expected benefit of this requirement. Given the limited number of verifiers, the standardized schedule is likely to create problems for project operators, verifiers, ARB, and approved offset registries. The cost impacts imposed on small projects by this market restriction would be especially pronounced, assuming they can even find a qualified verifier willing to undertake a small project. A more flexible verification schedule would help avoid this problem as well as the deadline issues discussed above. CERP urges ARB to provide more flexibility in the timing of verification. One option would be for ARB to require offset project operators to submit evidence that verification has been initiated (e.g. a signed verification contract) within three months of the end of the prior data collection period. This would help to ensure that projects undergo verification promptly, while allowing offset project operators and verifiers to responsibly manage the verification process. (CERP1)

Comment: ARB proposes to disallow issuance of offsets in cases where a final Verification Statement is submitted after a certain calendar date. Further, ARB has proposed a deadline associated with the submission of Offset Project Data Reports, which also, if not met, will result in the disqualification of offsets (for that verification year). This penalty is extremely harsh. Offset projects are often subject to technical issues or questions of protocol interpretation, which can result in lengthy resolutions, occasionally leading to public consultation or expert review. Further, it is not out of the ordinary for projects to require additional measurements, modeling or instrument calibrations. In many of these cases the project is robust, fully operational, and generating high quality offsets, and is only lacking in technical evidence that can take time to develop. Also, delays can, and often are, caused by verifiers themselves, at no fault of the project operator. Equator strongly urges ARB to modify this rule. (EQUATOR)

Comment: The regulations disqualify emission reductions quantified in an offset project data report or a verification statement that is submitted after the relevant deadline. This penalty is excessively harsh and should be modified. The regulations require that an Offset Project Data Report be submitted within three months of the end of the calendar year, which is also the emission data collection period. The verification statement for those emission reductions must be submitted within nine months of the end of the calendar year data collection period. The regulations also appear to provide that if one of these deadlines is missed, the emission reductions in the report or statement become permanently ineligible for crediting. Both the deadlines and the consequence for missing them are unreasonable. When emission reduction quantification and verification are going smoothly, a project will likely be able to meet these deadlines. When problems arise, however, it may take time to resolve them. Given the many and varied reasons that quantification and verification could be delayed, the disqualification of emission reductions after a missed deadline is unwarranted. CERP recognizes the need for ARB to ensure that projects are verified in a timely manner. CERP urges ARB to modify the proposed regulations to allow offset project operators and verifiers to apply for a deadline extension should such extenuating circumstances arise, with no penalty. (CERP1)

Comment: To avoid artificially inflating the cost of verification and of offsets, we recommend that ARB allow offset project data reports to be submitted at any time within one year of the relevant vintage year, with offset verification statements due six months after the submission of an offset project data report. Requiring all offset project data reports to be submitted by April 1 and all offset verification statements to be received by ARB by October 1 of the same year will concentrate demand for scarce verification services in the six month time period between April and October, driving up the cost of verification and therefore the cost of offsets. By permitting offset project data reports to be submitted within one year of the relevant vintage year, with offset verification statements due six months after the submission of the data report, ARB will smooth demand for verification services over time and avoid artificially inflating the cost of verification and offsets. This will also smooth workflow for ARB throughout the year (section 95976(d)(6) and section 95977(d)). (SHILLINGLAW1)

Comment: Section 95977(d) sets a nine-month time limit for the submission of verification statements after the monitoring period's completion. While we agree that in general this should allow sufficient time to complete a verification, there can be incidents which significantly derail the verification process and which are beyond the control of the Offset Project Operator or even the verifier. Examples include: loss of critical Verification Body staff due to turnover, illness, or untimely death; lengthy delays in obtaining documentation or opinions required from a regulatory agency, product manufacturer, previous project owner, or anyone else without a material interest in the project's timely verification; process bottlenecks including, especially, internal review processes at verification bodies if there is a calendar-year verification cycle for all projects. To accommodate these unusual circumstances, we request that ARB allow one-time extension requests to accommodate situations where the Offset Project Operator has acted diligently and in a timely manner yet cannot meet the deadline. (TPI2)

Comment: We fully support the necessity of a clear timeline for submitting project data. Requiring submission of all offset project data on April 1 of each year, as established in section 95976(d), however, will create a severe bottleneck and disable the offset program during that period. By requiring annual reporting on a single reporting deadline, the Air Resources Board is setting the verification schedule for all projects to be coincident, which will create undue burden on the verification bodies and board or registry staff reviewing the reported data. This requirement will, in turn, reduce the total number of projects that can be verified in any given year, increase the price of verifications, cause delays in offset credit issuance, and ultimately reduce the available supply of offset credits. A more efficient and effective timeline is to have data covering an approved reporting period submitted regularly, as specified in the Compliance Offset Protocol for that project type or based on the first time a project has been submitted. (CAR1)

Comment: Forcing offset projects into calendar-year reporting cycles places extraordinary pressure on all actors in the segment due to workload cyclicality without providing any commensurate environmental or marketplace benefit. Section 95976(d) is the first reference to calendar date requirements for submittal of offset project data reports and verifications, so we will elaborate here. We agree in general that frequent reporting and verification, usually annual but with some exceptions, is appropriate.

And, there are numerous requirements throughout the regulation which ensure that offset project data is reported on a frequent, uninterrupted basis. We do not believe there is any further benefit to forcing reporting and verification tasks into an identical January-to-December cycle. For example, ARB and Covered Entities will have identical information regarding the availability of offset credits whether they are verified on a calendar year basis or on an annual basis with arbitrary start and end dates. Registries can still submit annual audit documents. Therefore, we recommend that all references to calendar dates be removed, in favor of relative dates pegged to the last day of the monitoring period. Using this framework, section 95976(d)(6) would read: “All Offset Project Data Reports are due 91 calendar days after the last day of the project’s monitoring period.” Similar changes would be required to several other sections. Here are some examples: 95977(b)—simply end the section after the word “annually” in the first sentence; 95977(c) —eliminate reference to calendar year; 95977(d) —change dates to relative timeframes; 959857(b)(2)(E) —use the phrase “monitoring period” instead of “year.” (TPI2)

> **Response:** Section 95976(d) was modified to address stakeholder concerns about a calendar year reporting period with a fixed annual “verification period.” The new requirements cover a reporting period that is not tied to the calendar year to address these stakeholder concerns. Additional modifications were made to the timing for the schedule for verification (sections 95977(b) and (c)) and the submittal of Offset Verification Statements (section 95977(d)) to be consistent with the new offset reporting schedule in section 95976(d) and clarify the verification cycle. The new cycle requires that Offset Project Data Reports be submitted to ARB within four months after the conclusion of the Reporting Period. They subsequently have to be verified within nine months after the conclusion of the Reporting Period. We believe the new requirements provide sufficient flexibility to meet the deadlines. For an example, if a project developer

completes their reporting within two months, they have seven months to get their Offset Project Data Report verified.

M-93. Comment: Section 95977(b) specifies that non-sequestration offset projects be verified annually. In general, we support imposing annual verifications. However, certain projects, indeed certain project types, result in offset projects which produce very few offset credits each year, and for these projects annual verifications are a significant cost burden. For example, TerraPass works with many agricultural methane projects which produce fewer than 7500 credits per year; annual verifications impose a project cost of $1-2 per ton, just for the verifier, for a 7500 ton project. These projects have many co-benefits for example, they tend to be run by small business concerns or be publicly owned. For these small projects TerraPass recommends that the regulation provide flexibility to allow less-frequent verifications while maintaining annual monitoring report submissions. This flexibility could be provided in a several different ways:

A sentence could be added to 95977(b) which carves out an exception if such exception is written into the Compliance Offset Protocol – <u>"The verification of GHG emission reductions… must be performed annually unless otherwise allowed by the Compliance Offset Protocol.</u>"

A blanket exception for small projects could be written into the regulation: "<u>The verification of GHG emission reductions…. must be performed annually unless the Project's submitted Monitoring Report shows that the project produced fewer than 10,000 metric tons of emission reductions during the relevant Monitoring Period. In such cases, the Project Operator may choose to forego one verification and complete a two-year verification the following year. In no case shall a Project which opted for a two-year verification be awarded more credits for its first year than its Monitoring Report estimated</u>." (TPI2)

> **Response:** We agree that some exceptions need to be made for smaller projects, and we added provisions to allow smaller projects (those that yield 25,000 metric tons, or less, of GHG reductions or GHG removal enhancements) to opt to conduct verification every two years. In this case a site visit will only be required in the second year (the year in which full offset verification services are provided).

Verification

General Verification Comments

M-94. Comment: Offset verification provisions should be split into smaller sections. For ease of reading it would be preferable to split section 95977 into several separate sections. If necessary, this could be done using a decimal place in the way the sections on biofuel emissions are split: sections 95852, 95852.1, and 95852.2. (SCPPA2)

> **Response:** We agree and modified section 95977 to split it into three sections—95977, 95977.1, and 95977.2—for ease of readability.

M-95. Comment: Some mistakes fall below a materiality threshold where the potential for disruption of contractual arrangements outweighs the incremental gains from correcting the mistake. Camco recommends a materiality threshold of 5 percent. This is an issue which present in other offset mechanisms, particularly the CDM. A materiality threshold is especially warranted for types of mistakes that, if not corrected, are just as likely to understate as they are to overstate the emission reductions at the programmatic level, resulting in little to no net environmental impact. In these instances, it may be more productive to act prospectively through protocol revisions rather than revisiting prior emissions calculations. (CIG)

> **Response:** The program includes a materiality threshold of five percent. The term "offset material misstatement" can be found in section 95802, and is defined as 'a discrepancy, omission, or misreporting, or aggregation of the three, identified in the course of offset verification services that leads an offset verification team to believe that an Offset Project Data Report contains errors resulting in an overstatement of the reported total GHG emission reductions or GHG removal enhancements greater than 5 percent.' Discrepancies, omissions, misreporting, or an aggregation of the three, that result in an understatement of total reported GHG emission reductions or GHG removal enhancements in the Offset Project Data Report is not an offset material misstatement.

General Verification Process

M-96. (multiple comments)
Comment: Section 95977(e)(2)(C)(xii)(d) requires verifiers to run parallel calculations to determine the accuracy of the project's calculations. There are many different approved software models for forest carbon projects, some of which cost more than $20,000. This alone would significantly increase the cost of verification if a verifier has to purchase three or four different models and only performs five to ten verifications a year. In addition, the hourly cost to have a verifier reproduce the calculation will result in unworkable verification costs. We recommend that verifiers be required to check the equations used within the project's model for accuracy as they are currently required to do under the Climate Action Reserve verification requirements. (NISSENBAUM)

Comment: Section 95977(e)(2)(C)(xiv) requires verifiers to re-process project data and develop their own report to compare. This is excessive and would result in unworkable verification costs. (NISSENBAUM)

> **Response:** The regulation does not require that verifiers replicate offset calculations or reprocess data to compare results with those of project owners. Offset verification does not call for a duplication of all calculations, but rather checking specific subsets of the reported data based on several criteria. Selection of data subsets for checking involves a review of the largest

contributions to overall GHG sources, sinks, and reservoirs that result in reduction or removals, as well as the sources, sinks, and reservoirs associated with the greatest uncertainties in estimation. To do this, the verifier creates a sampling plan which includes a ranking of source contributions to overall GHG sources, sinks, and reservoirs, and a ranking of sources, sinks, and reservoirs with the greatest calculation uncertainty.

The proposed regulation does not prescribe the number of data checks that the offset verification team must perform. The offset verification team must exercise professional judgment in choosing these. Ultimately, the offset verification team must have reasonable assurance that the reported GHG reductions or GHG removal enhancements do not contain an offset material misstatement that would overestimate reductions or removals by more than five percent of what was reported in the Offset Project Data Report, and that all applicable regulatory requirements in the regulation and the applicable protocol have been met in the estimation and reporting of those GHG reduction or GHG removal enhancement estimates.

M-97. Comment: The requirement for use of professional judgment in sample size is concerning for project owners. The requirement for use of professional judgment will result in a "race to the bottom" by verifiers since the sample size dramatically impacts the price of verifications. The fewer samples a verifier thinks he may get away with, the lower the sample size he may recommend. Since the landowner relies on this professional judgment, not being an expert himself, it is impossible for him to know where the line is that will result in a higher risk of errors. Since ARB suggests that landowners bear the ultimate liability for errors, we suggest that ARB require a minimum sample size of 10 percent. (NISSENBAUM)

Response: We do not agree that we should require a minimum of 10 data checks for Offset Project Data Reports. The regulation does not prescribe the number of data checks that the offset verification team must perform. The offset verification team must exercise professional judgment in choosing these. Ultimately, the offset verification team must have reasonable assurance that: (1) the reported emissions reductions or removals do not contain a material misstatement that would overestimate reductions or removals, or a material misstatement that would underestimate reductions or removals, by more than five percent of the reported emissions reductions or removals, and (2) that all applicable regulatory requirements in the proposed regulation and the applicable protocol have been met in the estimation and reporting of those reduction or removal estimates. ARB will have oversight of its verification program to ensure consistency and quality across its verifiers.

M-98. Comment: Section 95977(e)(2)(C)(xix) allows the offset project operator or authorized project designee 10 days to correct a material misstatement or nonconformance found by the offset verification team. We believe 10 days is too short and recommend it be increased to 30 days. (NISSENBAUM)

Response: We do not agree that the number of days to modify the Offset Project Data report is too short. This provision provides those developing offset projects with 10 working days to modify and correct the Offset Project Data Report, and provides enough time for those developing offset projects to make the necessary changes to the report, while balancing the need to complete the verification in a timely fashion. The verification process is an iterative data review and revision process between an offset verifier and an Offset Project Operator or Authorized Project Designee. This particular provision provides a timeline to allow a verifier to wrap up verification-related services and provide an Offset Verification Statement before the due date.

M-99. Comment: The process of appealing from ARB decisions on projects should be more clearly defined. CERP urges ARB to provide more clarity on the process by which an offset project operator can appeal a decision of ARB regarding a project listing or verification. The timing of the appeal process should be modified as it may not be workable. If an offset project data report is found to be ineligible, the proposed regulations would give the offset project operator 30 calendar days to submit a revised version. (Note that it is problematic that there is no deadline for when ARB or the approved offset project registry must inform the offset project operator that the report has been found to be ineligible, especially as the 30 days begins from the date of the determination of ineligibility). A revised verification statement must be submitted within 15 calendar days. (It is unclear when this 15 day period begins). The proposed regulations further provide that if an offset project operator disagrees with a determination made by an approved registry, they can petition ARB, provided the process is reinitiated within 60 calendar days of the applicable verification deadline. However, given that there is no deadline for when ARB or an approved offset registry must determine whether an offset project data report meets the specified requirements, or for when an approved offset project registry must determine whether a revised offset project data report and verification statement are acceptable, it may not be possible to meet the 60 day deadline. CERP urges ARB to eliminate the 60 day deadline, and instead require appeal to ARB within 30 calendar days of the final contested decision by the approved offset project registry. (CERP1)

Response: We do not agree that we should modify timing of the appeal process. However, we modified or deleted sections 95977(e)(2)(C)(xix)(a.) through (c.) and replaced with new section 95977.1(b)(3)(R)(5.). These changes reflect the deletion of Offset Project Registries from the appeals process for Adverse Verification statements. This was clarified to be consistent with the MRR so that the appeals process should reflect determinations made by the Executive Officer of ARB and that ARB should be the only one to make these determinations.

ARB's Role in Resolving Disputes

M-100. (multiple comments)
Comment: Modify section 95977(e)(2)(C)(xix)(a-c) as follows:

a. If the Offset Project Operator or Authorized Project Designee and the verification body cannot reach agreement on modifications to the Offset Project Data Report that result in a Positive Offset Verification or Qualified Positive Offset Verification Statement, due to a disagreement on the requirements of this article or Compliance Offset Protocol, the Offset Project Operator or Authorized Project Designee may petition the Executive Officer ~~or Offset Project Registry~~ to make a decision as to the verifiability of the submitted Offset Project Data Report.

b. If the Executive Officer ~~or Offset Project Registry~~ determines that the Offset Project Data Report does not meet the standards and requirements specified in this article, the Offset Project Operator or Authorized Project Designee shall have the opportunity to submit within 30 calendar days of the date of this decision any Offset Project Data Report revisions that address the Executive Officer's ~~or Offset Project Registry's~~ determination, for re-verification of the Offset Project Data Report. In re-verifying a revised Offset Project Data Report, the verification body and offset verification team shall be subject to the requirements in sections 95977(e)(2)(C)(xviii)(a) through 95977(e)(2)(C)(xviii)(d), and must submit the revised Offset Verification Statement to ARB ~~or the Offset Project Registry~~ within 15 days.

~~c. If the Offset Project Operator or Authorized Project Designee disagrees with a determination made by an Offset Project Registry, they can re-initiate the dispute resolution process in section 95977(e)(2)(C)(xix)(a) through the Executive Officer.~~

~~(i) The process must be reinitiated within 60 days of the applicable verification deadline.~~

~~(ii) The Executive Officer, verification body, Offset Project Operator or Authorized Project Designee shall be held to the requirements in section 95977(e)(2)(C)(xix)(b).~~

Modify section 95977(e)(2)(C)(xx) as follows:

(xx) Upon submission of the Offset Verification Statement to ARB ~~or the Offset Project Registry,~~ the Offset Project Data Report must be considered final and no further changes may be made. All verification requirements of this article shall be considered complete.

Modify section 95981(d)(5) as follows:

(5) If ARB determines the information submitted in sections 95981(d)(1) and (d)(4) does not meet the requirements for issuance of ARB offset credits, <u>then ARB may deny issuance of an offset credit.</u> The Offset Project Designee or

Authorized Project Operator may appeal ARB's decision by petitioning the Executive Officer, within 10 days of denial, for a review of submitted information in section 95981(d)(1) and (d)(4) and respond to any issues that prevent the issuance of ARB offset credits. (NRDC1)

Comment: CARB, as the regulatory authority in charge of ensuring that offsets represent real emission reductions, must have a clear role in key decisions regarding verification and offset acceptance or denial. For instance, in section 95977(e)(2)(C)(xix)(a-c), solely the CARB Executive Officer should handle petitions from offset developers disputing Verification Statements, make decisions on whether the Offset Project Data report meets proper standards, and make final determinations on resolving disputes. Section 95980 should allow the CARB Executive Officer explicit authority to deny any offset proposals that the Executive Officer finds does not meet relevant offset criteria. (LUDLOW)

Response: We agree with the suggested change to delete Offset Project Registries from the appeals process for Adverse Verification statements. This clarification was made to be consistent with the MRR and reflects stakeholder comments that the appeals process should only be limited to determinations made by the Executive Officer of ARB and that ARB should be the only one to make these determinations.

We agree with your suggestion to clarify that ARB makes the final determination on whether or not ARB offsets credits should be issued and meet all requirements of the regulation, and we added this text to the regulation.

Site Visits

M 101. Comment: To accommodate the possibility of two-year verification cycles as requested above for small projects, we recommend modifying the language of section 95977(e)(2)(C)(iv) to require a site visit with every verification, though not to be interpreted as a requirement for site visits more frequently than once per year. (TPI2)

Response: We changed the regulation to require that a site visit for non-sequestration projects must be conducted in the year that offset verification services occurs. For smaller projects that opt to conduct verification every two years, a site visit will only be required in the second year (the year in which full offset verification services are provided.

M-102. Comment: Verification requirements will result in unworkable costs. Section 95977 indicates that two site visits must be performed in the first year of a project's crediting period, which will double the verification costs and make most projects financially infeasible. In addition, this section requires that verifiers must replicate offset calculations for each project, as well as re-processing data to compare results with those of project owners. Equator suggests that ARB reconsider requiring costly and onerous verification requirements, and recommends deferring to the verification requirements of the Climate Action Reserve's Forest Project Protocol. (EQUATOR)

> **Response:** The commenter's interpretation of the language is incorrect. The language in original section 95977(e)(2)(C)(iv), now new section 959771.(b)(3)(D), requires that for non-sequestration offset projects a site visit be conducted every year. In addition, we added provisions for smaller projects that opt to conduct verification every two years. In this case, a site visit will only be required in the second year (the year in which full offset verification services are provided).
>
> For forest offset projects, a single site visit must be performed in the first year of operations for a forest project. In addition, a site visit is required at least once every six years in the year that offset verification services are provided. This could occur sooner than six years, since verification for forest projects must be performed at least once every six years.
>
> The regulation does not require that verifiers replicate offset calculations or reprocess data to compare results with those of project owners. Offset verification does not call for a duplication of all calculations, but rather checking specific subsets of the reported data based on several criteria. Selection of data subsets for checking involves a review of the largest contributions to overall GHG sources, sinks, and reservoirs that result in reduction or removals, as well as the sources, sinks, and reservoirs associated with the greatest estimation uncertainties. To do this, the verifier creates a sampling plan that includes a ranking of source contributions to overall GHG sources, sinks, and reservoirs and a ranking of sources, sinks, and reservoirs with the greatest calculation uncertainty.
>
> The proposed regulation does not prescribe the number of data checks that the offset verification team must perform. The offset verification team must exercise professional judgment in choosing these. Ultimately, the offset verification team must have reasonable assurance that the reported GHG reductions or GHG removal enhancements do not contain an offset material misstatement that would overestimate reductions or removals by more than five percent of what was reported in the Offset Project Data Report, and that all applicable regulatory requirements in the regulation and the applicable protocol have been met in the estimation and reporting of those GHG reduction or GHG removal enhancement estimates.

M-103. Comment: Section 95977(e)(2)(C)(iv) requires two site verifications to be performed in the first year of a project, once at initiation and another after the first year of operations. This requirement doubles the cost of verification in the first year. This further increases the minimum size requirement for a project to be financially feasible. We recommend that there only be one required site-verification every 6 years with only a single verification required in the first year. (NISSENBAUM)

Response: The commenter's interpretation of the language is incorrect. The language in original section 95977(e)(2)(C)(iv), now new section 959771.(b)(3)(D), requires that a single site visit must be performed in the first year of operations for a forest project. In addition, a site visit is required at least once every six years in the year that offset verification services are provided. This could occur sooner than six years, since verification for forest projects must be performed at least once every six years. We believe the language in the regulation already matches the recommendation.

M-104. Comment: Equator suggests that ARB modify its proposal to only require a verification site visit to forest projects every sixth year. Updated model outputs, maps and carbon calculations can be readily reviewed and verified without the need for a costly site visit. If a verifier, at any time, believes that a site visit is needed due to changes in management, reversals or other technical deviations this is at their discretion. However, Equator does not believe that an annual site visit is warranted, and will only result in increased costs without contributing to the overall rigor of the system. (EQUATOR)

Response: The regulation has been modified to address these concerns. For forest offset projects, a single site visit must be performed in the first year of operations for a forest project. In addition, a site visit is required at least once every six years in the year that offset verification services are provided. This could occur sooner than six years, since verification for forest projects must be performed at least once every six years.

M-105. Comment: Site visits by verifiers should only be required of sequestration projects once every six years, as conditions on the ground do not change significantly from year to year, and ARB has adequate remedies in the event of any reversal. Requiring annual site visits is unnecessary to ensure offset quality and will significantly increase the cost of forest carbon offsets.

Section 95977(c) makes no distinction between site visit verifications and desk review verifications in requiring the verification of sequestration projects to be performed "at least once every six years and may cover up to six years of GHG reductions or GHG removal enhancements." Section 95977(e)(2)(C)(iv) requires that "[f]or a forest or urban forest offset project, at least one accredited offset verifier in the offset verification team, including the project specialist, must make a site visit every year that offset verification services are provided. A site visit is also required after the first full calendar year of operations of an offset project."

As noted above, New Forests has found that site visit verifications can be an order of magnitude more costly than a desk verification of data. Forests grow slowly and in most circumstances there will be little change to a given site from year to year. ARB has adequate remedies in the event of a forest carbon reversal: if a forest landowner or offset project developer has engaged in fraudulent activity or made intentional material misstatements in an offset project data report, ARB will be able to impose significant economic sanctions under the proposed regulations and the State of California will be able to pursue jail time for the perpetrators due to perjury. Such penalties coupled with periodic site visits are sufficient to ensure MRV accuracy and offset quality. Requiring annual site visits is unnecessary to ensure offset quality and will significantly increase the cost of forest carbon offsets, making many projects uneconomic, particularly projects on non-industrial forest lands. We would recommend that ARB require a site visit once every six years for stand-alone forest carbon projects. A desk verification of an offset project data report should be required for issuance of compliance offset credits in the interim (section 95977(c) and section 95977(e)(2)(C)(iv)). (SHILLINGLAW1)

> **Response:** The regulation has been modified to address these concerns. For forest offset projects, a single site visit must be performed in the first year of operations for a forest project. In addition, a site visit is required at least once every six years in the year that offset verification services are provided. This could occur sooner than six years, since verification for forest projects must be performed at least once every six years.
>
> In addition, we included a requirement to allow for less-intensive verification for qualifying forest projects. This would allow desk reviews to be performed in the interim years that full offset verification services are not provided. ARB has maintained the requirement for site verification every six years and by including less-intensive verification requirements. Registry offset credits and ARB offset credits may be issued in the interim years if they meet the requirements of the regulation and the protocol.

M-106. Comment: There is no distinction made between site verification and desk verification in section 95977(c). At a minimum, a site verification costs upwards of $15,000 while desk verification can be as little as $2,500. Market swings and the time value of money both add pressure to smaller projects that cannot afford to do annual site verifications but need a steady issuance of credits. We recommend that ARB maintain the requirement for site verification every six years, but allow for offsets to be issued to projects in between site verifications based upon desk verification. (NISSENBAUM)

> **Response:** We included a requirement to allow for less-intensive verification for qualifying forest projects. This would allow desk reviews to be performed in the interim years that full offset verification services are not provided. ARB has maintained the requirement for site verification every six years, and by including less-intensive verification requirements. Registry offset credits and ARB offset credits may be issued in the interim years if they meet the requirements of the regulation and the protocol.

M-107. Comment: The requirement to perform site verification within one year after an unintentional reversal will be a significant financial obstacle for a small landowner. We recommend that ARB allow a desk verification to meet this requirement. (NISSENBAUM)

> **Response:** We do not believe that a desk review is appropriate after any type of reversal. After a reversal occurs, it is necessary to take direct samples and measurements to assess the inventory of the standing live carbon stocks within the offset project boundary. Such data cannot be collected via a desk review and can only be done through a site visit. It is necessary to secure these measurements, because according to the regulation, if a forest project's carbon stocks drop below its project baseline after a reversal, the project must be terminated. In the event of an unintentional reversal, the project may be reinitiated.

Offset Verifier Accreditation

M-108. (multiple comments)
Comment: I have concerns regarding the proposed Accreditation Requirements for Verifiers outlined in section 95132 of the proposed regulation and implore the Board not to adopt these requirements as currently written. Simply put, they are too weak. There is no reason for ARB to duplicate the work that has already been completed by ANSI to accredit third party verifiers. Thus, we recommend that ARB adopt ANSI's program. (FIRSTENVRON1, FIRSTENVRON2)

Comment: The proposed accreditation requirements for verifiers outlined in the proposed regulation are too weak and we encourage the Board to consider changes to the requirements as they are currently written. The proposed regulation does not assure the level of competency which is necessary to cultivate this market. If adopted, the requirements will undermine California's reputation as a world-wide leader in the field of climate mitigation, especially on projects involving carbon offsets. In addition, different sets of accreditation standards, one from the Air Resources Board and another from the American National Standards Institute (ANSI), will lead to confusion, error and ultimately disputed findings. The California Air Resources Board should consider adopting the ANSI program which has grown from the initial seven certified verification bodies in 2009 to over twenty today. (BCFSE)

Comment: The proposed offset regulation references section 95132 of CARB 's Mandatory Reporting Rule, which establishes accreditation requirements for verification bodies, lead verifiers and verifiers. This wide range of requirements will not provide the State of California with a consistent basis for granting accreditation and may expose it to liability not only as an accreditation body but also as a personnel certification body. As an accreditation system already exists in the U.S. not funded by tax payers in the State of California, it seems a wasteful endeavor for CARB to continue to invest the budget and resources to maintain such a system.

At the time when CARB was publishing its mandatory GHG reporting rule, ISO 14065 had not yet been published, and therefore it was not possible for CARB to incorporate

ANSI's program into its regulations. Instead, CARB developed its own process for accrediting verification bodies to provide services for its program. Now that ANSI's accreditation program is well established, this amendment to CARB's regulation is the perfect opportunity to adopt the ISO 14065 accreditation program and maintain consistency with regulations adopted by the other Western Climate Initiative (WCI) jurisdictions. Creating multiple accreditation programs with multiple verification processes will confuse rather than harmonize. If California is to link with other programs, there must be consistency in the verification process. Accreditation of verification bodies against ISO 14065 can help to achieve this much needed environmental integrity and will assure equal reliability of results.

The requirements of ANSI and other accreditation bodies do not need to be applied in isolation. As seen with other GHG programs, additional criteria can be layered into the existing requirements. ANSI recognizes the important role of regulatory bodies. The ANSI process would not prevent CARB from requiring additional requirements such as training and certification to be met by ISO 14065 accredited verification bodies operating in this jurisdiction. (ANSI1, ANSI2)

Comment: We recommend that ARB amend its language to meet the verification and validation standards developed by the International Organization for Standardization (ISO) and identified by the International Accreditation Forum (IAF) and the American National Standards Institute (ANSI) as requirements for accreditation. IAF is a global association of Conformity Assessment Accreditation Bodies in the fields of management systems, products, services, personnel, GHG validation/verification, and other similar programs of conformity assessments. Their goal is to ensure the continued competence of accredited certification bodies and the consistent application of international conformity assessment standards, such as ISO 14065, and to provide assurance of the equivalence of the operation of certification bodies across the world.

Starting with their similarities, both ARB and ANSI have provisions for:

- Modification, suspension, revocation, and an appellate process.
- Conflict of Interest (COI).
- Professional Liability Insurance.

The remaining three ARB requirements have diminished expectations:

- ARB and ANSI have different requirements for witnessing audits for the industry sectors. ARB has random oversight that is not linked to any industry sector. ANSI requires annual witness surveillance audits based on selective sampling of V/VB activities. In addition, witness assessments by sector group are required to pursue initial accreditation with ANSI.
- ARB and ANSI have different requirements to demonstrate competency, experience, and knowledge. ARB provides a grandfather provision for individual lead verifiers that is based on experience not competency. ANSI requires a documented management system for assessing verifier competency on a continual basis. The accreditation body then assesses a V/VB's criteria for

demonstrating competency against the requirements of ISO 14065 as well as IAF MD 6:2009 IAF Mandatory Document for the Application of ISO 14065, which contains additional team competency requirements.

- ARB and ANSI also have different requirements to demonstrate GHG protocol knowledge. ARB has a one-time test that can be retaken if the individual does not receive a score of 70 percent. Again, ANSI requires a more comprehensive assessment through a V/VB's internal procedures for the ongoing demonstration and assessment of competency above and beyond passing a one-time test.

Finally, ANSI has the following nine requirements that ARB does not address:

- Management system in V/VB office for validation and verification activities.
- Management system in V/VB office in conformance with ISO 14065.
- Management system in V/VB office recertified every two years with annual surveillance audits.
- Demonstration of audit skills in witnessed assessment.
- Demonstration of industry experience and knowledge.
- Justification for verification fees.
- Internal audit of V/VB's management system.
- Record retention.

The above-mentioned elements are necessary to ensure consistent, competent provision of verification services. ARB has not adopted and is silent on many of the requirements associated with best practices. ARB has no expectation of any management system, let alone one that is certified by another internationally accepted standard. There is no auditing or witnessing provision, nor any demonstration of industry experience required. Unfortunately, these weak requirements will result in weak Emissions Data Reports and Offset Data Reports. (AAVB)

Response: The ARB accreditation program was developed using international best practices as laid out in ISO 14065, which is the standard to which greenhouse gas verifiers need to be accredited. The ISO standards are meant to be guidelines that programs can use to develop and tailor for their own program needs. The standard is program neutral.

ARB's verification accreditation program is consistent with the ISO 14065 standard for accrediting verification bodies. The following list highlights the areas in ARB's verification body requirements that are inclusive of all of the major requirements in the ISO 14065 standard:

- Be a legal entity that can be held accountable;
- Possess an internal conflict-of-interest policy, mechanisms to monitor, and requirements to remove and control for conflicts if they arise;
- Maintain Liability Insurance;
- Competencies for sectors, if applicable;
- Requirements to form verification teams with appropriate skills for verification of special sectors;

- Take responsibility for any subcontractors potential for conflict of interest with the client and the quality of their work;
- Identify a verification team lead; and
- Maintain record retention requirements.

However, ARB has chosen to advance the requirements for accreditation past the ISO 14065 standard for verification bodies to the level of individual verifiers. This higher standard of verifier accreditation has only recently been considered by ISO as they sought to develop a new ISO 14066 standard that seeks to attain California's higher level of competency for verifiers. ARB chose to add such a requirement to ensure a competency standard at a level beyond that currently required by international best practices. This includes a minimum educational and work experience requirement for individual verifiers. It also includes training and accrediting verifiers as sector specialists. ARB has developed a training program that builds on international GHG auditing skills and ARB's regulatory requirements for reporting and verification. In the future, ARB's training program will be updated to include general offset verification and offset project-specific verification training for verifiers interested in providing verification services for offset projects to support the proposed cap-and-trade offsets program.

ARB is committed to continually evaluating the verification bodies' services as specified in the ARB's regulatory requirements and the verification bodies' professional care and conduct to ensure the integrity and consistency of verifications. As part of this oversight process, each reporting year, ARB staff will audit every active verification body to ensure verifiers are providing high-quality offset verification services. Audit findings and observations are sent to verification bodies at the completion of verification services in order for each verification body to take any necessary actions to improve their performance.

Rotation of Offset Verifiers

M-109. (multiple comments)
Comment: COPC urges CARB to streamline the conflict of interest requirements in the regulation. COPC believes that CARB's offset program may fail to take into account the fact that the pool of available verifiers is likely to be quite small, especially during early compliance periods. As currently drafted, the conflict rules appear to limit verifiers and project operators to single interactions once every three years. Given the small number of verifiers, this limitation is simply impracticable. The requirement that offset project operators change verifiers every six years and not utilize any verifier used by the operator on any project in the past three years will also be impracticable (see section 95979). There is a very real risk that the verification process described in the regulation will become a bottleneck in the approval of offsets. (COPC1)

Comment: Section 95979 of the proposed market rules contain detailed rules for preventing conflict of interest among verifiers of forest projects. We fully support rigorous conflict-of-interest rules, but have concerns that the rules may impose unnecessary costs and overly restrict a limited pool of available accredited verification bodies. In particular, the requirements for "rotation" of verification bodies in proposed regulation section 95977(e)(1) appears unnecessary to the extent that each of the concerns raised by ARB should be adequately addressed by the accreditation process rather than placing additional burdens on project developers that would increase verification costs and undermine efficiencies. See ISOR at IX-136 (stating that rotation is necessary to avoid bias, familiarity or complacency). We support and incorporate by reference the comments submitted by other project developers and verification bodies concerning these rules. (BLUESOURCE, FCC)

Comment: The requirement for replacement of your verifier every six years is problematic especially given cost and time involved in getting a verifier familiar with each forest offset project. (CFA)

> **Response:** We maintain that the rotation of verifiers at least once every six years is necessary to minimize any biases and avoid familiarity or complacency between those developing offset projects and the verification body. While no changes were made to the requirements for rotating verification bodies, original section 95977(e)(1), now new section 95977.1(a), dealing with rotation of verification bodies was modified to make it clear that the rotation of verification bodies must occur on an offset project basis. The intent of the language was not changed. These clarifications were made in response to stakeholder comments that it was unclear if the rotation of verification bodies every six years applied at the individual offset project level or at the Offset Project Operator level.

M-110. (multiple comments)

Comment: CERP respectfully urges ARB to revisit the conflict of interest requirements in the offset provisions. To be clear, the Coalition strongly believes that the offset program needs to be free of the contamination of conflicts of interest and supports the establishment of rigorous rules to provide such assurances. However, it is important to find a means to avoid conflicts of interest that still allows the offsets program to operate effectively. In particular, the regulations need to take into account the fact that the AB 32 program likely will have a relatively small universe of verifiers. There are not many companies with experience in offset verification, and many of these companies perform other, non-verification services for offset developers and other customers as a core part of their business model. The limited pool of available verifiers already is, and will continue to be, particularly challenging in the near-term for projects seeking early action crediting.

The conflicts-of-interest regime reflected in the current draft—which appears to limit verifiers and project operators to one-off interactions once every three years—is impracticable. Were the regulations finalized in their current form, the avoidance of conflicts of interest would come at the cost of a substantial backlog of projects awaiting verification, potential increases in verification costs, and a reduction in offset supply. For these reasons, CERP urges ARB to consider revisions to verifier replacement. The verifier replacement requirements must be adjusted because there will not be enough verifiers to allow offset project operators and authorized project designees to meet the requirements. If an offset project operator has multiple projects of a specific type, and after six years has to find a replacement verifier for each of those projects that has not worked for that operator for at least three years—there simply will not be enough verifiers with the requisite project type expertise to perform the verification.

CERP respectfully urges ARB to modify this requirement. One approach would be only to require the periodic change of verifier for a particular project, but without regard to whether the replacement verifier also has worked for the project operator on other projects. (CERP1)

Comment: ARB's proposed conflict of interest regulations require an offset project operator or project designee to change the verifier they use every six years, to a verifier that has not been used in the previous three years. Applying this rule to a project operator, who may manage or own multiple projects, is likely to result in significant delays in offset supply due to lack of qualified verifiers. Equator suggests that ARB change this requirement so that periodic changes in verifiers are required for projects, but not for project operators. (EQUATOR)

> **Response:** Original section 95977(e)(1), now new section 95977.1(a), dealing with rotation of verification bodies was modified to make it clear that the rotation of verification bodies must occur on an offset project basis. The intent of the language was not changed. These clarifications were made in response to stakeholder comments that it was unclear if the rotation of verification bodies every six years applied at the individual offset project level or at the Offset Project Operator level.

Offset Verifier Conflict of Interest

M-111. Comment: We request clarification on what constitutes an incentive. Because of the burdensome costs of verification, it makes financial sense to contract for batch verifications. Because what constitutes as an incentive is not defined, we cannot tell if receiving a discount for packaging together verifications will put projects at risk. (NISSENBAUM)

> **Response:** The term incentive is used in the context of conflict of interest where a gift or work in-kind may compromise the objective review of an Offset Project Data Report. A discount for batching verification services does not in itself jeopardize an objective review of Offset Project Data Reports.

M-112. Comment: Section 95977(e)(2)(C)(xxi) does not include any time frame or statute of limitations on when a conflict of interest must exist or be discovered in order to invalidate a verification statement. If a verification body is found to have had a high level of conflict of interest in 2009, but the verification at issue was completed in 2018 when no conflict of issue existed, this clause could potentially invalidate the verification statement issued in 2018, even if no conflict of interest existed in 2018. (VCS)

> **Response:** Original section 95977(e), now new section 95977.1, deals with the verification of GHG reductions and GHG removal enhancements, and not what constitutes a conflict of interest. The conflict-of-interest provisions can be found in section 95979. This section establishes that a conflict of interest must be high if certain criteria are met within the previous five years.

M-113. Comment: We are concerned that the conflict of interest requirements in the proposed regulation are too restrictive and may prevent high quality projects from obtaining verification and capable verifiers from providing quality service. PG&E recommends ARB develop a review and appeal process similar to that allowed for the modification of offset project data reports in section 95977(e)(2)(C)(xix)(a), which would allow companies to have potential conflicts of interest reviewed by the Executive Officer. (PGE1)

> **Response:** We do not believe that the conflict-of-interest requirements for offset projects are too restrictive. These provisions are necessary to ensure the integrity of the offsets system and to ensure that all reviews associated with the data from offset projects are unbiased and independent.

M-114. Comment: Forest carbon project development is a very small field with very few qualified individual. We recommend that ARB allow this conflict to be ameliorated by insulating potential conflicts of interest from interacting on the verification of a project. For example, a former employee of an offset project operator could not be designated as lead verifier on his former employers' project. (NISSENBAUM)

> **Response:** We did not make any changes to the regulation. The commenter's suggestion is contrary to the basic premise that an offset project be subject to an independent review. ARB will accredit new verifiers as part of implementation and do not foresee this as an issue.

Issuance of ARB Offset Credits and Registry Offset Credits

General Issuance Comments

M-115. (multiple comments)
Comment: Section 95981(d)(3) appears to conflict with section 95981(a). Please clarify. (VCS)

Comment: It is not clear how section 95981(d)(2) and (4) are different. (VCS)

> **Response:** We recognize the clarity issues with section 95981, and modified this section to apply only to the issuance of ARB offset credits. For ease of review, section 95981 is shown in complete strikeout and new section 95981 is

underlined. A new section 95981.1 was added that contains the process by which ARB would issue ARB offset credits. This new section and new section 95980.1 were added to establish the difference between the processing and issuing of a registry offset credit and an ARB offset credit.

Comment: The proposed regulatory deadlines are potentially very helpful in ensuring an efficient offsets program and predictable offset credit supply. Certain critical deadlines, however, are missing and others are unreasonably severe. The proposed regulations fail to impose deadlines at certain key junctures. In addition, the penalty for an offset project operator or a verifier missing a deadline is unreasonably severe. There are key points in the offset credit generation process where an offset project registry must act in order to facilitate the issuance of ARB offsets in exchange for approved registry offsets. In order for a project registered with an approved offset registry to obtain ARB credits, the offset registry must submit the relevant paperwork to ARB. The proposed regulations do not require the offset registry to complete this action within any specified period of time, giving ARB and the offset project operator no guarantee of timely credit issuance—even if the operator fulfills all of its responsibilities in a timely manner. The proposed regulations should be modified to require an offset registry to submit the required paperwork within five working days of receiving a transfer request from the offset project operator. If a transfer request is submitted before offset registry credit issuance, the proposed regulations should require the relevant paperwork to be submitted within five working days of credit issuance. In order for ARB to issue offset credits to a project registered through an approved offset project registry, the registry must first cancel the original credits. There is no deadline on this action, which creates excessive uncertainty for the credit owners. CERP urges ARB to require approved registries to cancel the relevant credits within one working day of receipt of a request from ARB. (CERP1)

Response: We changed the party responsible for submitting information for the issuance of ARB offset credits from the Offset Project Registry to the Offset Project Operator or Authorized Project Designee, to place the onus on the project proponent instead of the registry. This will ensure that the information is submitted as soon as the project proponent can provide it. Also, we added a requirement in section 95981.1(e) that Offset Project Registries remove, retire, or cancel registry offset credits within 10 calendar days of notification by ARB of issuance of ARB offset credits.

M-116. Comment: Adopt measures to incentivize the development of broadly applicable new protocols. Under the VCS program there is a financial incentive for developers to formulate and develop new protocols (known as “methodologies” under the VCS). Entities that successfully develop a methodology under the VCS Program receive a share of the issuance fee for credits issued using that methodology. This has motivated creativity and action to voluntarily reduce greenhouse gas emissions from a number of different sectors, and encourages protocol developers to make sure their protocols are robust, clear, broadly applicable, and scalable. Given that the development of protocols is a time and resource intensive process, we recommend that if CARB adopts protocols created by other programs with robust rules, it should recognize and compensate the program (and/or protocol developer) for the work involved in developing the protocol. It could do this by paying a licensing fee for a certain period of time, or perhaps a fee on a per credit issued basis. This would create a powerful incentive for the development of rigorous and broadly applicable protocols to be presented to CARB. (VCS)

> **Response:** There are no fees assessed for the issuance of ARB offset credits. Protocol developers have an incentive to develop new offset protocols because they are able to develop projects that are eligible to receive ARB offset credits that can be used for compliance in the cap-and-trade program. These offsets will trade at a premium because they can be used for compliance.

M-117. Comment: The regulations need to state that offsets are not automatically certified simply because CARB fails to issue approvals within its deadlines, including those in section 98951. (EDF1)

> **Response:** We agree and added new section 95981.1(d)(3) to allow ARB to deny any offset proposals that the Executive Officer finds do not meet relevant offset criteria.

Timing for Issuance

M-118. Comment: Section 95981 indicates a 15 business day delay between issuance and deposit of credits into a holding account. In most other systems, issuance and deposit are simultaneous and it is not clear why there is a need for a 3 week delay after issuance before transferring credits into a holding account. There is a total delay of 60 calendar days and 15 business days from the receipt of the verification statement until the project proponent receives the credits—nearly 3 months, which seems like an unnecessarily long period of time for what is essentially an automated function. (VCS)

> **Response:** We made changes to the timing for issuance of offset credits. We will review the Offset Verification Statement within 45 calendar days of receiving it (new section 95981(c)), issue ARB offset credits within 15 days of making the determination that the Offset Verification Statement is positive or a qualified positive (section 95981.1(a)), and transfer the ARB offset credits into the appropriate Holding Accounts (section 95981.1(f) and notify the recipients (section 95981.1(c)) within 15 days. We believe the notification and transfer of ARB offset credits into the appropriate Holding Accounts can be done simultaneously and do not have to occur consecutively.

M-119. Comment: The draft regulation suggests that offset credits may be issued only on an annual basis, and not more frequently. CARB should consider amending this to give the market flexibility to submit verification reports and request credit issuance on a more frequent basis if desired. Since the cap and trade regulation ends in 2020, CARB should consider what will happen to offset projects that may have a crediting period that extends beyond 2020. Will there be some mechanism to continue to allow such projects to be recognized or shifted to other registries and programs? This is a particular concern for forestry and sequestration-based projects with long crediting periods. (VCS)

> **Response:** We believe annual issuance of offsets is sufficient, and that there is no need for a shorter time frame. Allowing a shorter time frame could drastically increase the number of offset verifications and could cause there to be delays of ARB-accredited verifiers. We will continue to evaluate what the offsets program will look like post 2020 as part of future amendments to the rule.

M-120. Comment: The credit issuance timeline involves seemingly unnecessary delays, and should be shortened. Under the proposed regulations, ARB will have 15 calendar days after issuing credits to a project to notify the recipient(s). ARB will then have an additional 15 working days to transfer the credits to the recipients' accounts. It is difficult to understand why these two simple, mechanical actions would take so much time after ARB has already reviewed the project and determined how many credits to issue. CERP urges ARB to have notification and credit transfer follow more rapidly upon ARB's determination of the quantity of credits to be issued. (CERP1)

> **Response:** We believe the notification (section 95981.1(c)) and transfer of ARB offset credits into the appropriate Holding Accounts (section 95981.1(f)) can be done simultaneously and do not have to occur consecutively. The purpose of the notice is to notify the recipient of the ARB offset credits that the credits will be transferred to its account.

M-121. Comment: Generally, section 95981 lays out two different processes and two different timelines for issuance of offsets, depending on whether the project was submitted to ARB or submitted to an offset registry approved by ARB. We question why the process has different timelines if the approved offset registry's processes have already been approved by ARB. Second, the timelines seem unreasonably long. For example, taking more than six weeks to review a submitted verification statement; more than two weeks to notify an offset project operator that a credit has been issued (we would expect this to be instantaneous with issuance, by software); and three weeks to issue a credit once a determination has been made that an issuance is appropriate. We would expect the administrative process of issuance to take at most 5 calendar days. Note also, subsection (f) switches to "working days" when all other date references in the section are "calendar days." Finally, the language in this section and in section 95982 use the words "transfer," "issue" and "register" seemingly interchangeably so it is not clear whether there is a meaningful distinction which we are missing. (TPI2)

> **Response:** We clarified the process for issuance of registry offset credits and ARB offset credits by revising sections 95980 and 95981, and by adding new section 95980.1 and 95981.1. Sections 95980 and 95980.1 apply specifically to the issuance of registry offset credits; sections 95981 and 95981.1 apply specifically to the issuance of ARB offset credits.

We also made changes to the timing for issuance of offset credits. We will review the Offset Verification Statement within 45 calendar days of receiving it (new section 95981(c)), issue ARB offset credits within 15 days of making the determination that the Offset Verification Statement is positive or a qualified positive (section 95981.1(a)), and transfer the ARB offset credits into the appropriate Holding Accounts (section 95981.1(f) and notify the recipients (section 95981.1(c)) within 15 days. We believe the notification and transfer of ARB offset credits into the appropriate Holding Accounts can be done simultaneously and do not have to occur consecutively. The notice is just to notify the recipient of the ARB offset credits that the credits will be transferred to its account.

We are aware that section 95981.1(f) refers to working days instead of calendar days.

The term "transfer" used in sections 95981.1(f) and 95982(b) refers to the act of ARB moving the ARB offset credits into the accounts of the appropriate participants. The term "register" refers to the creation of serial numbers for the issued ARB offset credits and their transfer to the account of the appropriate participants. "Issue" refers to the determination made by ARB to create an ARB offset credit for a GHG reduction or GHG removal enhancement.

Authorized Project Designee

M-122. (multiple comments)
Comment: In section 95974, it is not clear whether one can designate an Authorized Project Designee after the project has been listed or whether this can only take place prior to listing. (VCS)

Comment: Section 95974 enables Offsets Project Operators to designate other entities to perform certain required duties. The capabilities and desires of an Offset Project Operator may change over time, especially the very long periods of time involved in crediting offset projects. Therefore, we recommend that an Offset Project Operator be able to designate an Authorized Project Designee at any time during the crediting period, not only at the time of project listing. (TPI2)

Response: Section 95974 was modified in response to stakeholder comments to clarify that an Offset Project Operator may designate an entity as an Authorized Project Designee at the time of offset project listing or any time after offset project listing, as long as that entity meets the requirements of section 95974(b).

M-123. Comment: The regulation requires that in the case a user or retiree is no longer in business that the Offset Project Operator or Authorized Project Designee must replace the offsets. Since there is significant latitude in what specific roles and responsibilities an Offset Project Operator can assign to an Authorized Project Designee and the requirement to repay offsets is a significant burden, it is important that a clearer distinction is made. We recommend that ARB amend this language so that the party required to repay offsets is clarified to be the party that signs the attestations set out in sections 95975 and 95976. (NISSENBAUM)

Response: We did not make this change to the regulation. We have clear enforcement authority over Offset Project Operators and any Authorized Project Designees. These parties can determine among themselves who will replace the invalidated ARB offset credits, and can specify these terms in any third-party contractual arrangements that they enter into with each other.

M-124. Comment: CERP strongly supports ARB's use of the "authorized project designee" role to enable a third party to be responsible for project registration and other tasks. This will significantly improve the efficiency of the offsets program. (CERP1)

Response: We appreciate the support.

Crediting Periods for Compliance Offset Projects

M-125. Comment: Clarify the project re-registration requirement. Section 95986(j)(3) of the draft regulation is not clear about whether projects that must re-register with CARB or a new external offset project registry will be able to start with a new crediting period or carry on with an existing crediting period. While it seems clear that future-generated offsets from an existing project would be issued in the new registry, it is not clear what would happen to the existing projects already issued offset credits. (VCS)

Response: Original section 95986(j), now section 95986(l), was modified to clarify what happens to offset projects that reside at an Offset Project Registry, whose approval has been suspended or revoked. These offset projects may transfer to another approved registry and continue their current crediting period. This change was necessary because stakeholders were concerned that their offset projects could be ineligible if an Offset Project Registry's approval was suspended or revoked.

In addition, new section (l)(3) allows offset projects that must transfer to another registry in the event their current registry's approval is revoked to qualify for a one-year crediting period extension. These modifications were made in response to stakeholder comments that switching Offset Project Registries could cause a delay in the reporting of GHG reductions and GHG removal enhancements and subsequently cause those reductions to be ineligible for crediting.

M-126. Comment: Section 95980(c) of the proposed regulation provides for the timing and duration of renewed crediting periods for offset projects. SCE asks that CARB staff clarify whether there is a limit on the number of times an offset project can be renewed. (SCE1)

Response: Original sections 95975(i)(1) and (2), now new sections 95975(k)(1) and (2), specify that crediting periods for non-sequestration offset projects can be renewed twice and that the crediting periods for sequestration offset projects are not subject to any renewal limits.

M-127. Comment: Renewal crediting periods should not be limited where projects remain additional. CERP supports ARB's determination to assign non-sequestration projects a crediting period of seven to ten years, although CERP believes that many project types will need a 10-year crediting period to ensure financial viability.

In addition, CERP strongly supports ARB's decision to allow non-sequestration projects to apply for two crediting period renewals rather than one, as was proposed earlier. Nevertheless, it is our view any arbitrary limit on crediting period renewals is unnecessary and inefficient. When applying for a renewed crediting period, an offset project is assessed against an up-to-date additionality standard. If a project is still generating additional emission reductions at the end of a third crediting period, there is no justification for shutting the project down and wasting cost-effective emission reductions. In addition, CERP urges ARB to make a clear statement in the proposed regulations that an offset project will be always be assessed against the compliance protocol in effect at the time the project is initially listed or, during subsequent crediting periods, against the protocol in effect at the time the project applies for a renewed crediting period. (CERP1)

Response: We believe the length of a crediting period must be finite to provide flexibility in the future to decide if certain offset project types are no longer valid for AB 32 compliance. This approach allows us to reevaluate and readjust project baseline and additionality requirements in the future if the regulatory environment changes, and if we determine that offset projects are no longer additional. The range of 7 to 10 years for non-sequestration projects and 10 to 30 years for sequestration projects will incentivize investment in these offset project types. Original sections 95975(i)(1) and (2), now new sections 95975(k)(1) and (2), specify that crediting periods for non-sequestration offset projects can be renewed twice and that the crediting periods for sequestration offset projects are not subject to any renewal limits.

M-128. Comment: Section 95975 (g), Timing for Offset Project Listing in a Renewed Crediting Period, states "The Offset Project Operator or Authorized Project Designee must submit the information in section 95975(c) for a renewed crediting period to ARB or an Offset Project Registry no earlier than 18 months and no later than 9 months from conclusion of the initial crediting period or a previous renewed crediting period." Is this meant to provide a total time window of 9 months or of 27 months? (TPI2)

Response: We modified section 95975 (g), now section 95975(i), to clarify the intent of this provision. The intent is to give a nine-month window, nine-months prior to the conclusion of the preceding crediting period, to submit the information to ARB. This gives ARB an appropriate time frame for assessing additionality and determining if the project must update to any new version of the applicable protocol.

M-129. Comment: The ARB should more proactively address the unavailability of offset credits, and should encourage long-term offset projects by preserving ARB's discretion to grant crediting periods longer than 10 years. The current state of offset market development in California and elsewhere strongly suggests that there will not be enough offsets available in the context of California's Cap-and- Trade Program. This problem will be exacerbated by the proposed regulation, because the proposed regulation would provide for certification of a limited class of offset projects and place restrictions on projects that would get credited. For example, the proposed regulation would only allow ARB to credit a non-sequestration offset project for a period not to exceed 10 years. PacifiCorp is concerned that this limitation would unnecessarily hamper long-term, high quality offset projects by creating a degree of uncertainty for potential investors. Investments in long- term offset projects would be less likely to occur given the realistic possibility that a future, discretionary decision by a regulatory agency will eliminate the investors' ability recoup the investment with a reasonable return. ARB should amend this provision to allow ARB to approve non-sequestration offset projects for a period of at least 7 years, and no more than 30 years; this would create additional incentives to invest in larger offset projects. (PACIFICOR1)

Response: We did not make this change in the regulation. The limitation on the crediting period is designed to ensure that projects are using more up-to-date factors (e.g., leakage, buffer account) and scientific standards in the future, and that they are still additional. For this reason we do not believe that a longer time frame is appropriate for non-sequestration projects.

M-130. (multiple comments)
Comment: Modify section 95972(b) as follows:

(b) Crediting Periods. . . . The crediting period for a reforestation project conforming to a protocol listed in either section 95973(a)(2)(C)(iv), 95990(b)(5)(D), or 95990(b)(5)(E) must be no less than 50 years and no greater than 100 years. The crediting period for any other sequestration project must be no less than 10 years and no greater than 30 years. (OFFSETSWG1)

Comment: A 30-year crediting period for sequestration projects is too short given the requirement for a 100-year maintenance period following the last credit which requires regular inventories, project reporting, and site verifications. The uncertainty of the length of a cap and trade program and unknown future costs are substantial deterrents from implementing a project. Adding an additional uncertainty of whether a forest owner will benefit for more than 30 years for a project which will have 130 years of associated costs is another disincentive. We recommend that ARB adopt a crediting period for forest carbon projects that is equivalent to the life of the forest carbon project. (NISSENBAUM)

> **Response:** We do not agree that the crediting period for forest carbon projects should be extended. The intent of a 25-year crediting period is not to limit sequestration of carbon and offset issuance from forest projects. In fact, renewal periods allow for forest projects to sequester carbon and obtain offset credits beyond the 25-year crediting period. A crediting period of 25 years allows for the updating of protocols, if necessary, ensuring that projects use the more up-to-date factors (e.g., leakage, buffer account) and scientific standards.

M-131. Comment: CARB's projections for offset supply rely heavily on ODS and forestry. However, there are several parameters in CARB's forestry protocol that will limit the development of forestry offset projects. First, CARB only provides a 25-year crediting period for forestry projects, yet requires a 100-year maintenance period following the last credit issuance. Although CARB indicates that it will provide crediting period renewals, it is uncertain whether eligibility requirements may change after the initial crediting period. Project developers will be wary of putting capital at risk if there is a burden and liability beyond the crediting period. We believe that the crediting period for forest projects should be commensurate with the permanence requirement. The second roadblock for developers is the 100-year permanence requirement following the issuance of the last offset credit. This restriction imposes a long tail of legal liability to project developers, one that extends well beyond AB 32's market design. This imposes obligations on forestry offset projects well beyond those of industrial and power sectors. (CE2CP)

> **Response:** The 25-year crediting period is designed to ensure that projects are using more up-to-date factors (e.g., leakage, buffer account) and scientific standards in the future. Forest projects are allowed to be renewed for subsequent 25-year periods without limitation. Forest projects are unique in that carbon sequestered and credited under these projects can be reversed. To ensure that the offsets created for the sequestered carbon are real and permanent, the carbon must be stored for a period of at least 100 years. Maintaining these obligations is essential to the environmental integrity of the program. Permanence issues do not exist for the types of reductions achieved by industrial and power sectors; therefore, the permanence obligations do not apply to these sectors.

Invalidation and forest reversals

Invalidation Provisions

M-132. (multiple comments)
Comment: Camco recommends that ARB establish a statute of limitations of one verification cycle for the correction of mistakes in the issuance of credits. One

verification cycle provides a process and a reasonable amount of time in which to uncover any mistakes that went undetected during the previous year's verification cycle and credit issuance process, while allowing for a reasonable degree of regulatory certainty and closure to existing contractual commitments. (CIG)

Comment: Regardless of where ARB assigns replacement liability, CERP also strongly urges ARB to put a statute of limitations on the "mistake" liability of one verification cycle, in order to make it commercially manageable. In addition, CERP asks that ARB provide greater specificity regarding what circumstances would justify a finding of ineligibility due to mistake. (CERP1)

Comment: Limit the time period during which erroneous documentation can lead to the requirement to acquire and cancel an equivalent amount. The draft regulations contain no statute of limitations limiting the time period during which erroneous documentation can lead to a offset invalidation. Maintaining the ability to reopen a case at any point in the future is completely out of touch with modern legal systems, where it is acknowledged that facts and evidence are obscured through the passage of time. Moreover, the omission of a time limit for invalidation means that the liable party will face unlimited and increasing levels of liability as long as they remain active in the Cap and Trade system. This makes the invalidation risk very difficult and increasingly expensive to manage, and will lead to long-term issues with market liquidity. IETA believes that the desire to maintain the integrity of the cap must be balanced with the desire to create and maintain a healthy market with manageable costs to participants. IETA suggests, ARB include in their cap-and-trade regulations a strict two year statute of limitations on the ability to find documentation erroneous. (IETA1)

> **Response:** Section 95985(b) was modified to establish a three-year statute of limitations for the invalidation of ARB offset credits if the Offset Project Data Report or a subsequent Offset Project Data Report, depending on project type, is verified by a different verifier within that time frame. If the offset project does not qualify under these requirements, the default statute of limitations is eight years. We believe that the three-year time period is sufficient to uncover any new information as long as the project has been reviewed by a second verifier. If it is not looked at by a second verifier, we believe that eight years is necessary to uncover any new information that could lead to the invalidation of ARB offset credits. We believe the eight-year statute of limitations is sufficient because it would allow two verification parties to examine the offset credits in question for continuous projects. We do not believe that one year would provide sufficient time to detect all relevant new information or uncover any mistakes that a verifier may have missed.

M-133. Comment: In Section 95985 of the proposed rule, ARB proposes a mechanism for the invalidation of offset credits. While Evolution Markets understands ARB's desire to maintain the environmental integrity of the offset program and ensure the State meets its greenhouse gas emissions reduction targets, this provision could have an adverse impact on investment in offset projects and liquidity in trading markets for California compliance instruments.

The ability for ARB to invalidate offsets that have already been issued by ARB, and perhaps submitted for compliance, under what Evolution Markets considers to be unnecessarily broad conditions would introduce an unacceptable element of uncertainty to the offset market. The result could be a reluctance of market participants to invest in offset projects and a difficulty in creating necessary liquidity in secondary offset markets. The best approach to ensuring the environmental integrity of the program is to put in place a robust system of protocols, validation, and verification, and thereby obviating the need for an invalidation process. Barring this, Evolution Markets recommends the following changes to the invalidation procedure:

Establish a Limitation on Invalidation: As currently written, the proposed rule sets no limitation on when ARB may invalidate issued credits. This makes the invalidation risk difficult to manage for all counterparties. It can also constrict capital investment and secondary market liquidity over the long term. Evolution Markets recommends establishing a time limit for the invalidation period, and we believe a two-year look back from the time of issuance is reasonable.

Establish Proper Criteria for Invalidation: Section 95985(b)(2) of the proposed rules states that credits can be invalidated in the event of errors in documentation "sufficient to warrant a reversal." Evolution Markets believes this to be too broad. Experience in other offset markets shows errors in documentation to be infrequent and most often caught during the verification process. Any errors discovered after issuance, however, are most likely so minor in nature that they do not justify the potential restriction on liquidity that is likely to occur under the current proposed rules. Evolution Markets recommends the criteria for reversal should only in the event of intentional fraud or malfeasance on the part of a project owner, verifier, or end user. (EVMKTS)

> **Response:** Section 95985(b) was modified to establish a three-year statute of limitations for the invalidation of ARB offset credits if the Offset Project Data Report or a subsequent Offset Project Data Report, depending on project type, is verified by a different verifier within that time frame. If the offset project does not qualify under these requirements, the default statute of limitations is eight years. ARB believes that the three-year time period is sufficient to uncover any new information as long as the project has been reviewed by a second verifier. If it is not looked at by a second verifier, ARB believes that eight years is necessary to uncover any new information that could lead to the invalidation of ARB offset credits. We believe the eight-year statute of limitations is sufficient because it would allow two verification parties to examine the offset credits in question for continuous projects.
>
> In addition, we included extensive modified provisions in section 95985 to make it clear what would trigger an invalidation, how ARB will invalidate offsets, and which offsets will need to be replaced.

M-134. (multiple comments)

Comment: There is no need to make a one-size-fits-all rule that buyer liability should apply to reversals of offsets. The protocol for each offset type could include analysis of the particular risks of reversal and perhaps identify methods to protect against this outcome, or incorporate insurance within the offset itself, to provide a remedy in the case of destruction. This would provide more certainty for the buyers of offsets and facilitate market trading of offsets. (CMTA1)

Comment: I would encourage you to eliminate buyer offset liability. Markets work when buyers know they buy a product that is transacted, that's stamped by the Air Resources Board and they can rely upon that without going back and undoing a transaction that occurred many times before. (MARGOLIS)

Comment: The Board should amend the offset provisions by shielding from liability any good faith purchaser of verified offsets. Imposing liability on offset purchasers would unfairly penalize covered entities who have relied on the offset verification process and otherwise fully adhered to program requirements. (CCC, MAZOWITA)

Comment: End-user liability will severely dampen the creation of offset credits as a tool for compliance. In a liquid secondary compliance market where issued offsets are usually fungible commodities, and where trades occur on a daily basis, oftentimes on electronic exchanges, it is both unreasonable and unnecessary to expect buyers to attempt to reach the original project operator to perform thorough and expensive due diligence on the project. This provision would undermine both liquidity and the goal to create fungible commodities as part of a well-functioning market. The market needs to have certainty that once an offset credit has been issued, it is as “good as gold.” Once a credit has been issued, it should be valid for compliance no matter who purchases it. In the rare circumstance where a problem is found it would be far better from a market-functioning perspective to require whichever entity holds liability for the “bad” credits to have to replace them by sourcing other offsets and retiring them, instead of mandating a cancellation of the credits at issue. If offset project operators, verifiers and others submit to the jurisdiction of CARB as required by this regulation, it is not clear why CARB would need to shift this liability onto entities that are least able to warrant or control the quality of offsets. Under the VCS, it is the project operator that guarantees the veracity of the reductions its project has generated. Additionally, section 95985(d) would shift the liability to the project operator only if the end-user no longer exists. This seems to be an arbitrary shift based on a circumstance outside of the control of the project operator. The project operator should either always be liable or it should never be. Its liability risks should not be dependent on the financial health of end-users to which it has no connection. (VCS)

Comment: Offsets should not be invalidated after issuance. Section 95985 provides that a California offset credit may be invalidated by ARB after issuance and that in the event of such an invalidation, the user of that offset credit would be required to replace it with another compliance instrument. The possible invalidation of offsets after issuance is often referred to as ‘buyer liability’, because it places responsibility for offset quality on the buyer and end-user of offsets, rather than on offset developers and suppliers. A buyer liability approach would:

- Increase transaction costs associated with offsets, and thus overall compliance costs, because it would require offset purchasers to duplicate the validation efforts already undertaken by ARB, and would require offset purchasers to enter into additional transactions to protect themselves in the event of invalidation.
- Reduce efficiency by moving responsibility for offset quality away from the entities best able to ensure it – project verifiers and suppliers – and placing it on offset buyers.
- Disadvantage California offset projects vis-à-vis offset projects in the Western Climate Initiative (WCI) and elsewhere, since these other offsets would not be subject to later invalidation.
- Create a high degree of market uncertainty for offset users and stifle investment in offset projects. (WPTF)

Comment: CARB should have the same requirements for the use of this type (forestry sequestration) of backup account and/or other insurance mechanisms for all offsets, even if it requires replacement as a first resort. CARB may also consider not requiring replacement first for offsets that it certifies without the use of a registry, to support the use of its offset program. (EDF1)

Comment: We recommend CARB eliminate buyer liability associated with offset reversals. Section 95985(d) requires that buyers suffer sanctions or replace credits that, though approved by the CARB, later turn out to be invalid (exceptions are provided in the event of credit invalidation owing to unintentional forest reversals per section 95985(f)). We recommend that CARB stand behind determinations when it decides which credits are allowed to be used as offsets, hold the initial creators of the credits responsible for maintaining the reduction. Consider setting up an insurance pool where a small part of allowances and/or offsets are shaved off and set aside and drawn upon in the event that a reversal cannot be otherwise resolved. A “buyer beware” approach will not work because it:

- is not practical, especially in situations where a credit may be created and then sold a number of times before it is used and applied;
- raises transaction costs; prior to each purchase, prudent buyers will need to re-verify the credits, audit the prior evaluations of the initial verifier, and look into their crystal ball to try to determine if the CARB or some third party will (perhaps several years after their creation) challenge the credits after they are purchased and applied to a project;
- would create two classes of separate and unequal credits – those issued by (and enjoying the full faith of) the government and those created through the offset market (which could always be undermined by some future legal challenge);
- is not consistent with historical practice in the emission allowance, emission reduction credit, or RECLAIM Trading Credit markets; and

- is reasonable to expect CARB, which approves every offset, to stand behind the offsets that it approves.

An approach that relies upon the use of high quality credit verifiers will not work because verifiers:

- are not officers of the government and do not have the ability to stand in CARB's shoes when it comes to determining if the credit creation activity meets the requirements of the rules as may be subsequently determined by CARB.;
- Cannot (and are not paid to monitor a project after the credits are claimed and/or transferred;
- Will, given the potential liabilities and likelihood of lawsuits (which may ensue after the credits are transferred/used), find it very challenging to secure professional liability insurance; and
- Will be unable to charge a fee that adequately compensates them for the cost of doing the initial and ongoing assessments, paying for liability insurance, and setting aside cash reserves in the event that any credits which have been reviewed by the verifier are subsequently determined to be bad.

Conveyance contracts cannot be written in a fashion to remove this risk because:

- Credits may change hands many times, each time with a different buyer and seller. While demanding performance from the initial project developer may be practical it becomes quite a different prospect when the credit has been purchased numerous times before it is used and discovered to be invalid. The cascading liabilities, multiple conveyance contracts, and the passage of time that are implicit in such a scenario will make it impossible for a buyer to gain resolution in the event of bad purchases; and
- The actual credits may be divided, segmented, and conglomerated into financial instruments that allow market participants to transact products that represent emission reductions from a variety of different offset creating projects. Again, it is impractical for buyers to conduct appropriate due diligence on the offset that will make up such a derivative product. So too will it be difficult for a seller of a financial product which represents an amalgam of credits from different projects to replace just that portion that are determined to be invalid.

Nor should CARB conclude that the problem of offset reversals can be managed through the use of financial derivative products. While such products may initially reduce the risk of purchasing offsets they will, if priced considering consequential damages, sell at prices that dramatically increase transaction costs. (CANTORCO2E)

Comment: SCPPA raises the following point to help ensure ARB's offset protocols and links to other offset programs provide ample cost-effective emission reduction options: The offset market will be weakened if buyers have primary liability for invalid offsets and cannot rely on the integrity of verified offsets. Placing liability on the verifier would be a straightforward and effective alternative to buyer liability. The ARB has the jurisdiction to do this. Section 95985(d) (p. A-160) requires that an entity that retires or uses an offset (other than a forestry offset) that is later found to be invalid must replace that offset. Verifiers, not buyers, should be liable for invalid offsets. Buyer liability would hamper the development of a liquid offset market. Verifiers should be required to replace invalid offsets. (SCPPA2)

Comment: There are multiple practical ways to handle offset invalidation that do not cause the financial burden to fall on a non-responsible party, and the regulation order should be changed to utilize one or more of them. The fundamental approach proposed for offset invalidation is ill-advised. Instead of focusing on recompense by the responsible party, the regulation order essentially creates a game of "musical chairs" whereby the party unlucky enough to be holding the invalidated credit "when the music stops" is left holding the financial responsibility. Instead, "make-good" for invalidation should be the responsibility of the offset credit creator. (MSCG2)

Comment: Place the liability for invalidated/erroneous offset credits on the project owner. In a fully functioning carbon market, the end users of offset credits will have a similar connection to a surrendered offset as a person has to the dollar in their pocket before they hand it to the cashier. Most likely, they were not responsible for the project that led to its issuance, and they should not be held liable for either an intentional reversal related to that project or any errors made in the documentation of that project. Discouraging the purchase and holding of offsets, such responsibility lies with the project owner, and thus any related liability for the erroneous issuance of offset credits should logically be placed on the project owner as well. (IETA1)

> **Response:** We do not agree that we should eliminate buyer liability associated with the invalidation of ARB offset credits. Requiring the user to replace the invalidated offsets ensures that purchasers and users of offset credits do their due diligence in seeking out high-quality offset credits. We have clear enforcement authority over covered entities that will be using ARB offsets for compliance. If the covered entity replaces any invalidated offset credits, they may then take appropriate action through third-party contractual arrangements they may have established prior to purchase. These arrangements currently exist in the voluntary offset market, and we expect that as the offset market becomes more established, that additional mechanisms to deal with the risk of invalidation will also be established. In the event that the offset credit has not yet been used or retired, it will be canceled in the market tracking system and removed from any Holding or Compliance Accounts. These provisions in no way diminish ARB's authority to assess penalties under section 96014 on any offset project developer or verifier that has provided false information to ARB.

M-135. Comment: We have serious concerns with the offset credit replacement provisions included in this section. As a point of background, we believe that the economic burden imposed by a replacement ton provision greatly exceeds, by more than an order of magnitude, the economic burden imposed by typical ARB enforcement proceedings. For example, if a project's verification is reversed because the verification data was found to be wrong or inaccurate (e.g., using incorrect weather data on a dairy project), the economic burden of replacing those tons will be in the hundreds of thousands of dollars. Furthermore, it is unlikely that any individual entity within the chain of responsible parties received economic benefit at a level anywhere close to the cost of replacement tons. Also, we note that the replacement provision is in addition to ARB's ordinary enforcement authority and ability to levy penalties. When addressing non-sequestration projects where credits cannot be physically reversed, we have two categories of conduct which might result in credit invalidation. First, we have human error by the ARB, the verifier, the Offset Project Operator, the Offset Project Designee, or other parties; second we have intentional misrepresentations or fraud. The replacement provision, which as noted above is far more punitive than ARB's enforcement practice from an economic standpoint, treats these behaviors as equal. We believe that human error should be treated as error, and if the ARB chooses to conduct an enforcement action against the responsible party they should do so, but without imposing a replacement ton provision. If they choose to do so, the ARB's enforcement division could establish fines based on the cost of replacement tons. Alternatively, the ARB could establish a small non-sequestration buffer pool to cover non-fraudulent actions while maintaining the integrity of the cap, and use its enforcement authority to deter such error. In cases of fraud or other intentional misconduct, we recommend that the ARB use its full enforcement authority and levy fines which are at least sufficient to replace the invalidated credits. In neither of these cases is a provision in the regulation that requires replacement of the tons necessary. We recommend deletion of all reference to this requirement. (TPI2)

Response: We do not agree that we should eliminate buyer liability associated with the invalidation of ARB offset credits. Requiring the user to replace the invalidated offsets ensures that purchasers and users of offset credits do their due diligence in seeking out high-quality offset credits. We have clear enforcement authority over covered entities that will be using ARB offsets for compliance. If the covered entity replaces any invalidated offset credits, they may then take appropriate action through third-party contractual arrangements they may have established prior to purchase. These arrangements currently exist in the voluntary offset market, and we expect that as the offset market becomes more established, that additional mechanisms to deal with the risk of invalidation will also be established. In the event that the offset credit has not yet been used or retired, it will be canceled in the market tracking system and removed from any Holding or Compliance Accounts. These provisions in no way diminish ARB's authority to assess penalties under section 96014 on any offset project developer or verifier that has provided false information to ARB.

We included extensive modified provisions in section 95985 to make it clear what would trigger an invalidation, how ARB will invalidate offsets, and which offsets will need to be replaced. We believe that these changes provide clarity on this point.

M-136. (multiple comments)
Comment: NextEra Energy feels that once an offset credit is certified, it should remain viable and not be revocable. In section 95983 of proposed rule, ARB is providing for the invalidation of already certified offset credits. The purchaser the offset credit assumes "buyer liability" and would be required to replace any invalidated offsets with either another certified offset or another compliance instrument. The viability of the offset credit should be the responsibility of the certification process, registered certifying agents, and the offset provider. In many cases the purchaser of the offset credit will be completing transactions through a third party and not be directly involved with the offset project. The purchaser should be able to trust the certification of the ARB to assure what they are buying is a real reduction in GHG emissions and that it qualifies for use as a compliance tool in the GHG cap and trade program.

Permanence of certified offsets is necessary to ensure this provision acts an effective cost containment mechanism. The current proposed regulation leaves offset purchasers and project developers in a position of uncertainty. The potential invalidation of certified offset credits will result in fewer projects moving forward and therefore fewer GHG emissions reductions as well as reducing the amount of potential the co-benefits created by these projects.

The proposed buyer liability approach…Reduces the demand for offset projects due to an additional risk to both the investors in the projects themselves and the purchasers of the offsets. The risk and uncertainty injected into the market could result in less investment in potential projects and/or the development of new project technologies. The proposed buyer liability approach…Increases the cost of offsets to the purchasers because an independent evaluation of the projects by the purchaser of the credits would be necessary.

In addition, buyers of offset credits have to purchase additional assurances or hedge financial positions to protect against this added risk. This is ironic because offsets are listed as a cost containment mechanism. The proposed buyer liability approach…Moves some level of accountability for offset credit verification from the experts in this arena (certifying agents) and shifts it to non-experts (buyers).

It places California offset projects at a disadvantage to out-of-state projects that do not institute this reversibility provision in their rules. (RGGI projects, WCI projects, non-cap and trade states/regions.)

There are options the ARB could exercise prior to the issuance of a credit that could mitigate the potential voiding of an offset credit. For instance, there may be projects at risk for the release previously sequestered carbon as the result of an action outside of the projects direct control (i.e. earthquake, fire, etc). ARB would need to identify those types of projects and assign a discount factor to the total offset production of every project certified under that protocol. This factor should be established based on the risk of sequestration or offset reversal. All the discounted offsets are then placed into a general holding account. If it is determined that a reversal has occurred, an equivalent amount of offsets are retired from this holding account. All offset projects of a particular type would share the risk of the offset reversal and there is no need to invalidate any of the offsets. The GHG cap integrity is maintained. This also gives assurances to investors up front so their risk in developing new projects is limited. If the holding account is exhausted or reversals from a specific project type are reoccurring, ARB can then either adjust the discount factor or revisit the verification protocol.

Once an offset is certified, it should remain viable and non-revocable. One example of establishing a policy of non-reversal has been proposed in British Columbia. WCI also recognizes the need for assurances of offset credits to retain their value.[Proposed Offset Regulation Consultants paper, page 17 at: http://www.env.gov.bc.ca/cas/mitigation/ggrcta/offsets- regulation/index.html#Intentions] NextEra urges ARB to establish robust offset protocols and establish the policy that offsets once certified are not reversible. (NEXTERAENERGY)

Comment: Section 95985(d) requires the user or retiree of the offset credit to replace each metric ton of CO_2e with another approved compliance instrument, in the event ARB determines that a previously issued offset credit is invalid. We understand the desire to ensure that offsets represent real reductions in emissions to safeguard the environmental integrity of the program. However, Shell Energy believes that placing revocation liability on offset users, who usually have no direct control over an offset project or intentional reversal, will dramatically discourage the trading of such offsets, and drive the market towards inefficient, illiquid bilateral transactions with no price transparency; every transaction would have to negotiate liability for revocation. An actual revocation would trigger a waterfall of contractual default provisions that would be costly to administer. Also, it would be impossible for an exchange to list a standard offset contract in this regard. Only through frequent trading of offsets will reliable price signals occur, making it imperative to structure any government recourse in a way that does not impede the liquidity of the market.

We believe that ARB can achieve their intended objective of environmental integrity without placing the liability on the users of offsets. The proposed regulation would only allow offsets credits that meet the stringent ARB approved protocol and that have been verified by ARB approved verifiers. Section 96010 clearly establishes ARB's authority over project developers as well as purchasers/users of offset credits.

We recommend that the liability for invalidated/erroneous offset credits (for example due to intentional reversals, fraud or material errors/mistakes) be placed on the project developers that have control over and responsibility for operating successful offset projects. Therefore this section should be amended as follows:

Section 95985 (d) If an offset credit found to be invalid pursuant to this section, except as provided in section 95985(e) and (f), has been retired or surrendered for compliance in any voluntary or regulatory program, the project developer of that offset credit must retire an additional metric ton of CO e of another approved compliance instrument pursuant to sub article 4, within 30 calendar days pursuant to this section. (SHELLENERGY)

Response: We do not agree that we should eliminate buyer liability associated with the invalidation of ARB offset credits. Requiring the user to replace the invalidated offsets ensures that purchasers and users of offset credits do their due diligence in seeking out high-quality offset credits. We have clear enforcement authority over covered entities that will be using ARB offsets for compliance. If the covered entity replaces any invalidated offset credits, they may then take appropriate action through third-party contractual arrangements they may have established prior to purchase. These arrangements currently exist in the voluntary offset market, and we expect that as the offset market becomes more established, that additional mechanisms to deal with the risk of invalidation will also be established. In the event that the offset credit has not yet been used or retired, it will be canceled in the market tracking system and removed from any Holding or Compliance Accounts. These provisions in no way diminish ARB's authority to assess penalties under section 96014 on any offset project developer or verifier that has provided false information to ARB.

We made clarifications to both sections 95983 and 95985 to address stakeholder concerns that the regulatory language requires that offset credits be double-compensated in the event of reversals. Section 95983(b)(2) now states that ARB will retire a quantity of ARB offset credits from the Forest Buffer Account in the event of an unintentional reversal. Sections 95983(c) and (d) specify that in the event of an intentional reversal the Forest Owner must replace ARB offset credits to ARB in the amount specified in the regulation. Also, in new section 95985(c)(4)(B) we specify that reversals do not constitute an invalidation, and if a reversal occurs, the provisions in section 95983 apply.

M-137. Comment: Invalidating an offset after it has been verified and issued significantly increases the risk profile of offsets and reduces their value. The registration of a carbon offset is an expensive and tedious process and is specifically designed to ensure the final registered offset represents a carbon reduction that is real, verifiable, additional, and permanent. We recommend that ARB eliminate the potential for invalidation and ensure integrity of the system through the threat of suspension of verifiers and Authorized Project Designees. If necessary, we also recommend that ARB protect against the potential of errors and omissions by requiring projects to submit offsets to a buffer pool similar to the forest buffer pool. The loss in value of offsets compared to allowances is likely to be ten to twenty-five percent while a buffer pool contribution of five percent (or one in twenty tons) is far more than should be necessary to address the pooled risk of errors and omissions. (NISSENBAUM)

Response: We do not agree that we should eliminate buyer liability associated with the invalidation of ARB offset credits. Requiring the user to replace the invalidated offsets ensures that purchasers and users of offset credits do their due diligence in seeking out high-quality offset credits. We have clear enforcement authority over covered entities that will be using ARB offsets for compliance. If the covered entity replaces any invalidated offset credits, they may then take appropriate action through third-party contractual arrangements they may have established prior to purchase. These arrangements currently exist in the voluntary offset market, and we expect that as the offset market becomes more established, that additional mechanisms to deal with the risk of invalidation will also be established. In the event that the offset credit has not yet been used or retired, it will be canceled in the market tracking system and removed from any Holding or Compliance Accounts. These provisions in no way diminish ARB's authority to assess penalties under section 96014 on any offset project developer or verifier that has provided false information to ARB.

In addition, an invalidation and a reversal are two separate occurrences, and they are handled differently in the regulation. We made clarifications to both sections 95983 and 95985 to address stakeholder concerns that the regulatory language requires that offset credits be double-compensated in the event of reversals. Section 95983(b)(2) now states that ARB will retire a quantity of ARB offset credits from the Forest Buffer Account in the event of an unintentional reversal. Sections 95983(c) and (d) specify that in the event of an intentional reversal the Forest Owner must replace ARB offset credits to ARB in the amount specified in the regulation. Also, in new section 95985(c)(4)(B) we specify that reversals do not constitute an invalidation, and if a reversal occurs, the provisions in section 95983 apply.

M-138. Comment: Replace ability to invalidate offset credits with requirement to acquire and cancel equivalent amount. Sec 95985 of ARB's Cap and Trade draft regulations stipulates that offset credits can be invalidated after issuance. IETA understands and shares ARB's desire to maintain the environmental integrity of the emissions cap, but believes that providing ARB the ability to invalidate issued offset credits is the wrong avenue to do so. The Alberta government audits offset projects after the offsets have been produced and submitted for compliance by regulated facilities. Depending on the results of the audit, the government may accept or revoke all or a portion of the offsets. California's proposal to invalidate issued offsets is likely to lead to the same risk, threatening compliance, increasing administrative costs and decreasing offset supply.
To resolve this, IETA proposes ARB requires the liable party acquire and submit for cancelation an equivalent amount of offset credits *or* allowances. This change will continue to ensure the integrity of the cap, while allowing a measure of flexibility to market participants. (IETA)

Response: We do not agree that an offset credit should remain viable under all conditions. To ensure the enforceability of compliance offsets, we need to have the ability to investigate and take action for violations or noncompliance with the proposed regulation. In the event of fraud or malfeasance on the part of project developers or verifiers, there may be cause to invalidate offset credits after they have been issued, to protect the environmental integrity of the program. These provisions in no way diminish ARB's authority to assess penalties under section 96014 on any offset project developer or verifier that has provided false information to ARB.

The regulation does require that an equivalent amount of offsets be submitted to replace the invalidated offsets. We included extensive modified provisions in section 95985 to make it clear what would trigger an invalidation, how ARB will invalidate offsets, and which offsets will need to be replaced. We believe that these changes provide enough flexibility for the market to handle the risk of invalidation while maintaining the environmental integrity of the program.

M-139. Comment: The retirees of offsets are saddled with too many responsibilities regarding the validity of the underlying credit project. The Sanitation Districts believe that if there is offset reversal, the offset developer should bear the burden of making the system whole. Within California, GHG offsets will become more difficult to generate because of their indirect connection with the upcoming stricter ozone standards that focus on the criteria co-pollutants. As a result, GHG offset projects will be counted against needed NOx and VOC reductions and will be incorporated into the SIP, thereby creating an impossible additionality test. (LASD1)

Response: We do not agree that the responsible party of an invalidated ARB offset credit should be the offset developer. We have clear enforcement authority over covered entities that will be using ARB offsets for compliance. If the covered entity replaces any invalidated offset credits, they may then take appropriate action through third-party contractual arrangements they may have established prior to purchase. These arrangements currently exist in the voluntary offset market, and we expect that as the offset market becomes more established, that additional mechanisms to deal with the risk of invalidation will also be established. In the event that the offset credit has not yet been used or retired, it will be canceled in the market tracking system and removed from any Holding or Compliance Accounts. Requiring the user to replace the invalidated offsets ensures that purchasers and users of offset credits do their due diligence in seeking out high-quality offset credits.

M-140. (multiple comments)
Comment: Provide greater clarity on factors that would support a determination that are "sufficient to warrant a reversal" of an issued offset credit. (OFFSETSWG1)

Comment: The draft regulations stipulate that credits can be found erroneous in the event of errors in documentation "sufficient to warrant a reversal." IETA believes that this criteria section 95985 (b)(2) should be further defined. The criteria for reversal should be in the event of intentional fraud or malfeasance on the part of a project owner, verifier, or end user. This reversal risk can then be managed in contracting between the parties involved in the project activity. Errors without intent are infrequent and so minor in nature that they do not justify the potential restriction on liquidity that is likely to occur under the current proposed rules. (IETA1)

Comment: Section 95985 (d) makes reference to the actions ARB will take if a retired or surrendered offset credit is found to be invalid, including actions ARB will take if such credit has been retired under a voluntary program. The ARB has no authority over voluntary programs (with the possible limited exception of opt-in participants to the ARB regulatory program), so the requirements and enforcement provisions listed here as pertaining to voluntary program retirements should be deleted. Instead, the ARB should commit to notifying the retiree of the voluntary program credit's invalidation so that the retiree may take appropriate private action with the voluntary program authority. Of course, the ARB's general enforcement authority, which is separate from the obligations imposed here related to replacement tons, remains in force as allowed by statute. (TPI2)

> **Response:** We included extensive modified provisions in section 95985 to make it clear what would trigger an invalidation, how ARB will invalidate offsets, and which offsets will need to be replaced. We believe that these changes provide clarity on this point.

M-141. Comment: Section 95985(b) of the proposed regulation states that an offset credit may be invalid if ARB determines that errors by "Offset Project Developers... or others involved in producing the documentation used to support the issuance of offset credits are sufficient to warrant a reversal." Section 95985(d) goes on to provide that if an offset credit is found to be invalid it must be replaced with another approved compliance instrument within 30 calendar days. Given the complexity of the project and verification protocols, there will undoubtedly be good faith errors involved in the documentation used to support the issuance of an offset credit. Consequently, the vague standard for determining whether errors are "sufficient to warrant reversal," and the harsh remedy proposed where such a determination is made, will likely discourage offset project development. We therefore recommend that ARB consider adopting a gross negligence or intent threshold for the imposition of the 95985(d) remedy. We further recommend that ARB consider allowing offsets that are invalidated as a result of a good faith error to be replaced pro rata over the remainder of the project's crediting period rather than within 30 days. (TCF)

> **Response:** We included extensive modified provisions in section 95985 to make it clear what would trigger an invalidation, how ARB will invalidate offsets, and which offsets will need to be replaced.
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> We also changed the timing for when the responsible party must replace the invalidated ARB offsets from 30 days to six months. This should provide enough flexibility for those that must replace invalidated offsets to purchase additional compliance instruments, while still ensuring that the environmental integrity of the cap is maintained.

M-142. Comment: The regulation proposes to hold buyer's liable in the event of offset reversals. The burden to rectify an offset reversal falls on the buyer regardless of whether the reversal is intentional or unintentional, but enforcement and penalties are far more egregious in the case of an intentional reversal. According to the regulation, CARB will give a buyer 30 days to correct an intentional offset reversal. Failure to do so will constitute a violation resulting in CARB assessing penalties. CalChamber opposes buyer liability amongst regulated entities and believes that enforcement of such liability ignores the purpose of approved offsets and a certification process supported by a third party verifier. Imposition of liability upon the buyer creates uncertainty that could suppress the market. (CALCHAMBER1)

> **Response:** We do not agree that we should eliminate buyer liability associated with the invalidation of ARB offset credits. Requiring the user to replace the invalidated offsets ensures that purchasers and users of offset credits do their due diligence in seeking out high-quality offset credits. We have clear enforcement authority over covered entities that will be using ARB offsets for compliance. If the covered entity replaces any invalidated offset credits, they may then take appropriate action through third-party contractual arrangements they may have established prior to purchase. These arrangements currently exist in the voluntary offset market, and we expect that as the offset market becomes more established, that additional mechanisms to deal with the risk of invalidation will also be established. In the event that the offset credit has not yet been used or retired, it will be canceled in the market tracking system and removed from any Holding or Compliance Accounts. These provisions in no way diminish ARB's authority to assess penalties under section 96014 on any offset project developer or verifier that has provided false information to ARB.
>
> We also changed the timing for when the responsible party must replace the invalidated ARB offsets from 30 days to six months. This should provide enough flexibility for those that must replace invalidated offsets to purchase additional compliance instruments, while still ensuring that the environmental integrity of the cap is maintained.

M-143. (multiple comments)
Comment: Camco believes that the cancellation of credits due to mistake is too drastic of a response that risks unfairly stigmatizing market participants and disrupting pre-existing contracts. Camco understands why, in cases of fraud, the cancellation of credits may be warranted to preserve market integrity. For credits that have been issued by mistake, however, little will be served by cancellation of the credits that could not be equally accomplished by less disruptive means. Specifically, ARB could require that the responsible party account for and replace the missing emissions reductions through the purchase and retirement of additional credits. With respect to those mistakes that do make it through the verification and credit issuance process undetected, Camco request that ARB provide additional guidelines on which situations warrant correction retroactively. (CIG)

Comment: ARB does not need to rely on buyer-liability to ensure the quality of California offsets. ARB itself can enforce the validity of offsets, and ensure that additional compliance instruments are surrendered to cover any deficient offsets. Rather than invalidating offsets after issuance, ARB should require that, as a condition for accreditation of project verifiers and as a condition for issuance of offset credits to project developers, those entities must retire additional compliance instruments in the event that any offsets are found deficient due to that entity's negligence or misconduct. (WPTF)

> **Response:** To maintain the integrity of the program, we believe it is important to remove and disqualify the ARB offset credits that are directly related to the invalidation, as opposed to requiring that the responsible party just replace the instruments and allowing the serial numbers of the invalidated offsets to remain in the tracking system. If the ARB offset credits should not have been issued, we do not want them to be in our system, and the serial numbers that are directly affected will be made public. We cannot have a case where a complying entity has submitted a serial number for compliance that is associated with an invalidated offset.
>
> The regulation does require that an equivalent amount of offsets be submitted to replace the invalidated offsets. We included extensive modified provisions in section 95985 to make it clear what would trigger an invalidation, how ARB will invalidate offsets, and which offsets will need to be replaced. We believe that these changes provide enough flexibility for the market to handle the risk of invalidation while maintaining the environmental integrity of the program.

M-144. Comment: Buyer liability in the event of fraud or mistake will needlessly make the offsets market less liquid, and creates inefficient incentives. CERP strongly opposes the buyer liability framework in the proposed regulations. Under the proposed regulations, if already-issued offset credits are found to be ineligible due to mistake or fraud, the credits will be canceled from any holding account. Any credits that have already been submitted for compliance will also be canceled, and the entity that submitted the credit will be responsible for replacing the credit. This cancellation and replacement requirement will make offsets non-homogenous (because many offset sale contracts will incorporate a tailored credit-replacement clause) and reduce the liquidity of the offsets market. CERP urges ARB to instead allow already-issued credits to remain valid, and require the relevant offset project operators or verifiers to submit an equivalent quantity of replacement credits to be retired. This system would place the replacement liability with one of the parties that have the greatest control over the quality of emission-relevant data and reporting. It will also help ensure that offsets will be a homogenous, liquid commodity. Failing to place the liability on the party with control over the risk unfairly penalizes innocent parties, and generates considerable inefficiency in the market. The replacement liability is imposed on a party without good information about the actual risk of ineligibility, which will lead to the risk being inefficiently overvalued. As a result, the offsets market will not function efficiently and the costs of obtaining offsets will rise. ARB can avoid all of these deleterious outcomes by imposing the replacement liability where it belongs—with the party that is responsible for the mistake or fraud. (CERP1)

Response: To maintain the integrity of the program, we believe it is important to remove and disqualify the ARB offset credits that are directly related to the invalidation, as opposed to requiring that the responsible party just replace the instruments and allowing the serial numbers of the invalidated offsets to remain in the tracking system. If the ARB offset credits should not have been issued, we do not want them to be in our system and the serial numbers that are directly affected will be made public. We cannot have a case where a complying entity has submitted a serial number for compliance that is associated with an invalidated offset.

Requiring the user to replace the invalidated offsets ensures that purchasers and users of offset credits do their due diligence in seeking out high-quality offset credits. We have clear enforcement authority over covered entities that will be using ARB offsets for compliance. If the covered entity replaces any invalidated offset credits, they may then take appropriate action through third-party contractual arrangements they may have established prior to purchase. These arrangements currently exist in the voluntary offset market, and we expect that as the offset market becomes more established, that additional mechanisms to deal with the risk of invalidation will also be established. In the event that the offset credit has not yet been used or retired, it will be canceled in the market tracking system and removed from any Holding or Compliance Accounts. These provisions in no way diminish ARB's authority to assess penalties under section 96014 on any offset project developer or verifier that has provided false information to ARB.

M-145. Comment: For mistakes of a more material and systemic nature that do warrant correcting retroactively, Camco recommends that the appropriate response should be to account for and replace the missing emissions reductions through the purchase and retirement of additional credits, rather than the invalidation of already issued credits. Camco respectfully submits that the same environmental results could be achieved by issuing a corrective order requiring the responsible party to account for the shortfall through additional credit purchases. If that order is not complied with within a reasonable time, then the cancellation of existing credits and other corrective actions may be warranted. At a minimum, Camco recommends that ARB state in the regulations or accompanying guidance that it will determine on a case-by-case basis whether the invalidation of credits is warranted to preserve market integrity, or whether the proper accounting and replacement of the emission reductions could achieve the same objective with less disruption to existing contractual and institutional arrangements. (CIG)

Response: To maintain the integrity of the program, we believe it is important to remove and disqualify the ARB offset credits that are directly related to the invalidation, as opposed to requiring that the responsible party just replace the instruments and allowing the serial numbers of the invalidated offsets to remain in the tracking system. If the ARB offset credits should not have been issued, we do not want them to be in our system and the serial numbers that are directly affected will be made public. We cannot have a case where a complying entity has submitted a serial number for compliance that is associated with an invalidated offset.

Clarification of Reversals and Invalidation

M-146. Comment: One of the basic criteria for offsets along with being a real reduction and additional is the idea of permanence. The ability of ARB to invalidate certified offsets at some future date contradicts that criterion. The mechanism for the verification and certification of offset credits needs to supply the purchaser with the confidence that what they are buying will remain viable. (NEXTERAENERGY)

Response: We clarified the regulation by adding new section 95985(c)(4)(B). In this provision we specify that reversals do not constitute an invalidation, and if a reversal occurs, the provisions in section 95983 apply. By relying on the Forest Buffer Account we are ensuring permanence of sequestered carbon. An invalidation would only be found if information was omitted or there was fraudulent or new information submitted to ARB that would lead ARB to find that ARB offset credits should not have been issued.

M-147. (multiple comments)
Comment: The forestry sequestration reversal provisions should not require double compensation for a reversal. CERP strongly supports ARB's establishment of a "buffer reserve" to compensate the offset program in the event that a forest sequestration project experiences an unintentional reversal. If an intentional reversal occurs, the proposed regulations also require the offset project operator to submit to ARB an amount of credits equivalent to the reversal, which appropriately puts the replacement obligation on the entity with the greatest control over the project's success. However, the proposed regulations—in addition to providing these replacement provisions—appear to require that the offset credits issued for emission sequestrations that subsequently undergo a reversal be canceled. If the reversal is unintentional, an equivalent quantity of credits from the buffer reserve is cancelled. This makes the offset program whole. (Note: any credits in the reserve that represent a reversed sequestration must also be canceled). If the reversal is intentional, an equivalent quantity of credits must be submitted to ARB by the offset project operator, and will be cancelled. This makes the offset program whole. The credits representing the reversed sequestration are cancelled under section 95985. At this point, the offsets program has been compensated for the reversal twice. If the already-issued credits are canceled, then the buffer reserve and the replacement obligation serve no purpose, and forestry offset credits will be non-homogenous and illiquid.

CERP strongly recommends that ARB remove the section 95985 requirement for cancellation in the event of a forest sequestration reversal, and rely instead on the buffer reserve and project operator liability mechanisms to address reversals. In addition, CERP urges ARB to harmonize the requirements applying to forestry projects that undergo an intentional reversal. In the proposed regulation order, it provides that a project that undergoes an intentional reversal is automatically terminated. The ARB U.S. Forest Project Protocol, however, sensibly provides that if a forestry project experiences a reversal but its actual live standing carbon stocks are still above approved baseline levels, it may continue without termination provided the reversal has been compensated. The approach taken by the protocol is both reasonable and appropriate. So long as live standing carbon stocks remain above baseline levels, the project has generated real, additional, verifiable carbon sequestration and should continue. Minor “reversals” are also a fact of life. In the course of a 100 year forestry management project, typical silvicultural practices may require harvesting beyond the levels envisioned by a protocol in order to balance tree age classes and sustainable forest growth. (CERP1)

Comment: The Reserve is pleased that the Air Resources Board recognized the importance of addressing reversals. However, invalidation of offset credits every time a reversal occurs as proposed under section 95983 and section 95985 will create severe unintended consequences and reduce confidence in the overall program, as buyers of credits will be uncertain if their credits will be invalidated at some later date due to actions beyond their control. Reversals, intentional or otherwise, may be effectively remedied by simply retiring compliance instruments, including other offset credits, in proportion to the reversal. This is, in fact, what the Regulation stipulates in the case of unintentional reversals (section 95985(f)). The same requirement should hold for intentional reversals, i.e., the Offset Project Operator or Authorized Project Designee should simply be required to retire compliance instruments, not “replace” invalidated credits. The practical effect from an emissions integrity standpoint would be identical, and retirement would avoid the unnecessary administrative transactions and possible legal disputes associated with invalidating credits (possibly in multiple buyer or end-user accounts) and “replacing” those credits with alternative instruments provided by the Offset Project Operator or Authorized Designee. (CAR1)

Comment: The ARB should clearly define why and under what conditions it would reverse an offset credit so that there is transparency in the market and protection for the consumer. CCEEB recommends the obligation to replace offset tons due to reversals should be treated differently depending on the cause of the reversal. For intentional or fraud-related reversals, such as when a forest offset developer decides to harvest the forest, then the developer who is making the business decision should be responsible for replacing the lost carbon sequestration. For unintentional reversals due to causes such as forest loss from fire, pests, disease, or bankruptcy, the lost carbon should be replaced from a reserve held back when credits are issued for such projects. (CCEEB1)

> **Response:** We made clarifications to both sections 95983 and 95985 to address stakeholder concerns that the regulatory language requires that offset credits be double-compensated in the event of reversals. Section 95983(b)(2) now states that ARB will retire a quantity of ARB offset credits from the Forest Buffer Account in the event of an unintentional reversal. Sections 95983(c) and (d)

specify that in the event of an intentional reversal the Forest Owner must replace ARB offset credits to ARB in the amount specified in the regulation. Also, in new section 95985(c)(4)(B) we specify that reversals do not constitute an invalidation, and if a reversal occurs, the provisions in section 95983 apply.

M-148. Comment: Intentional reversals should be remedied by the Forest Owner but not cause the invalidation of transacted offset credits and the removal of such credits from any Holding or Compliance account. Buyer liability should only be imposed for fraud or significant errors in the system. (sections 95983(e)(3) and 95985)). The drafting of these sections is somewhat ambiguous and would appear to require both the replacement of reversed tonnes and the cancellation of transacted credits in the event of a reversal from a forest carbon offset project. As a general principle, a reversal of an obligated reduction should be compensated for in the system once to ensure atmospheric integrity, but the proposed system would require a reversal to be compensated for twice.

Consider the following scenario: a landowner sells an offset credit representing 1 tCO_2e to an entity with compliance obligations under AB 32. That landowner's project then suffers an intentional reversal of 1 tCO_2e. ARB exercises its discretion to determine that the offset credit sold is invalid pursuant to section 95983(e)(3) and section 95985(b)(1). The offset credit in the compliance buyer's Holding or Compliance account is therefore cancelled and removed by ARB pursuant to section 95985(c). As required by section 95985(e), the Offset Project Operator or Authorized Project Designee must replace the 1 t CO_2e, and they do so by purchasing an offset or other compliance instrument and retiring it. In this scenario, two compliance instruments have been canceled or retired to compensate for the reversal of one compliance instrument by the forest owner, the original offset canceled pursuant to section 95985(c), and the compliance instrument purchased and retired pursuant to section 95985(e). If the reversal is adequately compensated through the forest owner purchasing and retiring a compliance instrument pursuant to section 95985(e), and there is therefore a net zero emission to the atmosphere, why also cancel the transacted credit?

We would recommend that buyer liability apply only for significant errors or fraud in the system pursuant to section 95985(b)(2), and that intentional and unintentional reversals from forest carbon offset projects be addressed solely through section 95985(e) and (f), which fully maintain atmospheric integrity. Modify section 95985 as follows:

> (b) An offset credit may be determined to be invalid for the following reasons: ~~(1) a finding pursuant to section 95983 that a reversal occurred in a forest sequestration project; or (2)~~(1) ARB has determined that errors warrant a reversal.
>
> (d) If an offset credit found to be invalid pursuant to ~~this~~ section - 95985(b) above, ~~except as provided in section 95985(e) and (f),~~ has been retired.

(e) If an intentional reversal occurs from a forest offset project. within 30 calendar days of being notified by ARB. If the Offset Project Operator or Authorized Project Designee does not replace the ~~invalid~~ reversed offset credit(s)**.** will constitute a violation.

(f) If an unintentional reversal occurs from a forest offset project, ARB will retire offset credits in the amount of tons reversed from the Forest Buffer Account. ~~All other invalidated offset credits must be replaced pursuant to section 95985(d).~~" [*this last sentence is redundant and with the changes to 95985(b) above an unintentional reversal will not trigger an invalidation of credits*].

These changes would enable ARB to cancel a credit for significant errors or fraud in the system, and to require forest owners or authorized designees to replace intentionally reversed credits, while avoiding the requirement of an unnecessary double cancellation of compliance instruments solely in the instance of forest carbon offset reversal.

If ARB decides to continue to require the cancellation of transacted offset credits due to a landowner's reversal – in addition to requiring the landowner to make the system whole – compliance buyers will a) avoid forest carbon offsets; b) discount forest carbon offset prices if they must purchase forest carbon offsets; and c) impose liability for replacing any cancelled credits contractually on the forest owner or authorized designee, thereby placing a forest owner in a situation in which he or she must purchase two compliance instruments for every one tonne reversed. In such circumstances few forest owners will seek to supply the market. (SHILLINGLAW1)

Response: We made clarifications to both sections 95983 and 95985 to address stakeholder concerns that the regulatory language requires that offset credits be double-compensated in the event of reversals. Section 95983(b)(2) now states that ARB will retire a quantity of ARB offset credits from the Forest Buffer Account in the event of an unintentional reversal. Sections 95983(c) and (d) specify that in the event of an intentional reversal the Forest Owner must replace ARB offset credits to ARB in the amount specified in the regulation. Also, in new section 95985(c)(4)(B) we specify that reversals do not constitute an invalidation, and if a reversal occurs, the provisions in section 95983 apply.

In addition, we included extensive modified provisions in section 95985 to make it clear what would trigger an invalidation, how ARB will invalidate offsets, and which offsets will need to be replaced.

M-149. Comment: It is unclear what happens if offsets are subsequently discredited. The project is terminated and section 95983 provides for "offset reversals." However, if compliance depends on the purchase of the subject offsets, it is not clear if or how the affected facility will be held accountable, especially in the case of "unintentional reversals," which can happen without adequate notice. (CAPCOA1, CAPCOA2)

Response: In the case of intentional reversals in the forest sector, the Forest Owner is responsible for placing the reversed tons (sections 95983(c) and (d)). In the case of an unintentional reversal, ARB will remove ARB offset credits from the forest buffer account to cover the reversed tons (section 95983(b)(2)). The holder and/or covered entity is not responsible for replacement in the case of forest reversals. To make it more clear in new section 95985(c)(4)(B), we specify that reversals do not constitute an invalidation, and if a reversal occurs, the provisions in section 95983 apply.

Reversals in the Forest Sector

M-150. Comment: An intentional reversal should only trigger a requirement for the replacement of each metric tonne reversed. (section 95985(e)). This section contains some ambiguity as to whether it is only the reversed volume of CO_2e that must be replaced or the obligated reductions of the entire project. Modify section 95985(e) for clarity as follows:

If an intentional reversal occurs from a forest offset project, the Offset Project Operator or Authorized Project Designee must ~~replace~~ retire a volume of approved compliance instruments pursuant to subarticle 4 equivalent to the volume of metric tonne of CO_2e reversed ~~pursuant to subarticle 4~~, within 30 calendar days of being notified by ARB. (SHILLINGLAW1)

Response: Original section 95985(b)(7) was moved to new section 95985(c)(4)(A). New section 95985(c)(4)(B) was added to clarify that reversals for forest offset projects do not trigger an invalidation and reversals will be handled according to section 95983. This provision was added to alleviate stakeholder concerns that any reversal would trigger invalidation and that the forest owner would have to double compensate for those tons. New section 95983(c)(3) requires that Forest Owner replace ARB offset credits with valid compliance instruments in the case of an intentional reversal. And a new requirement was added to section 95983(c) that states ARB offset credits will be retired from the Forest Buffer Account if the reversed tons are not replaced by the Forest Owner within the 90 days. If the Forest Owner does not replace the ARB offsets within the 90 days and ARB offset credits are retired from the Forest Buffer Account, ARB will assess penalties pursuant to section 96014. This allows the program to be made whole and still requires that the responsible party is appropriately penalized for not making the program whole.

M-151. Comment: Section 95983(b)(2) provides that if CARB determines there has been an unintentional reversal of offsets, it will retire a quantity of offset credits pursuant to section 95985(e). SCE believes this reference should read “section 95985(f).” (SCE1)

Response: Original section 95985(e) has been deleted and section 95983 (b)(2) was modified to clarify that ARB will retire a quantity of ARB offset credits in the amount of metric tons of CO_2e reversed from the Forest Buffer Account in the case of an unintentional reversal.

M-152. Comment: CARB should remove the distinction between intentional and unintentional reversals in the forest buffer account provisions. Section 95983 of the draft regulation distinguishes between intentional and unintentional reversals of offset credits in the context of forestry projects. The VCSA strongly recommends that CARB consider alternative approaches that do not rely on distinguishing between intentional and unintentional reversals. The reason for this is that it can be difficult to determine whether reversals are intentional or unintentional, particularly in developing country jurisdictions where strong property law protections and legal enforcement may either not exist or be applied consistently. For instance, one could imagine a scenario in which a landowner hires someone to burn down the forest so that the project can be terminated and crops planted without having to replace offset credits, all the while making the occurrence appear to be unintentional. Since the vast majority of REDD projects will occur in developing countries, the unintentional/intentional distinction is likely to be very difficult to determine and thus may hinder the development of REDD projects and/or undermine the integrity of the buffer system. (VCS)

Response: According to the regulation, the Offset Project Operator or Authorized Project Designee must notify ARB of any reversal and provide a description of the reversal. In addition, the forest project must be verified within one year of the occurrence. This will provide sufficient data for ARB to determine whether a reversal is intentional or unintentional. Furthermore, sector-based offset credits, including REDD, would not be dealt with under these provisions. The provisions in subarticle 13 only apply to those offset projects developed under Compliance Offset Protocols. Compliance Offset Protocols are only applicable in North America. If REDD projects were to be allowed in the future, there would be a separate rulemaking to determine the rules surrounding those projects. Rules surrounding these projects would be found in subarticle 14 since they would be offsets issued by other recognized programs.

Permanence

M-153. Comment: The VCSA recommends that CARB accept alternative non-permanence management approaches than what is currently featured in the draft regulation. Although the currently proposed framework may be appropriate for the two domestic forestry-related protocols CARB has already endorsed, this framework could be highly problematic for non U.S. forest offsets that may enter the system through section 95973 (Requirements for Offset Projects Using ARB Compliance Offset Protocols). (VCS)

Response: Currently ARB's Compliance Offset Protocol, U.S. Forest Projects, only applies to forest projects in the United States. ARB would have to adopt additional protocols for forest projects outside of the United States. Any new protocols will be part of a new rulemaking, in which ARB could amend the rules in the regulation, if determined to be necessary. We believe the Forest Buffer Account in the regulation is a robust method to account for any non-permanence issues.

M-154. (multiple comments)
Comment: The VCSA recommends that CARB add language to section 95983 of the regulation about how the agency will accept other robust approaches for managing reversals if they meet certain quality standards, and the VCSA would gladly cooperate to assist in the development of the language needed to achieve this. The VCS risk tool assesses all potential reversal risks and establishes buffer withholding requirements in a manner that will maintain atmospheric integrity (and the permanence of all credits issued) without needing to distinguish between intentional and unintentional reversals. Many experts believe this approach to be more comprehensive and robust than a reversal management system that is dependent on hard-to-make determinations about intentionality. (VCS)

Comment: The Forest Carbon Developers support the use of a buffer pool to insure against unintentional reversals. Forest Protocol section 7.2. In addition, we encourage ARB to provide flexibility to approve alternative insurance mechanisms that provide equivalent certainty, such as those may be developed by the marketplace or proposed by project sponsors. (BLUESOURCE, FCC)

Response: To ensure permanence of GHG reductions and GHG removals ARB will manage the risk of reversals through the Forest Buffer Account. We believe this mechanism provides enough flexibility for developers of forest offset projects to manage the risk of potential reversals, and we do not see a need for additional mechanisms within the regulation.

M-155. Comment: The inclusion of forestry and land use offsets in a positive list of projects fails to address questions of permanence surrounding carbon sinks, or consider the impact that the use of such sinks has in delaying the transition from a fossil-fuel based economic model. (CTW)

Response: Currently the only sequestration project types included in the regulation is Compliance Offset Protocol, U.S. Forest Projects and Compliance Offset Protocol, Urban Forest Projects. To ensure permanence of GHG reductions and GHG removals, ARB will manage the risk of reversals through the Forest Buffer Account. We believe the Forest Buffer Account in the regulation is a robust method to account for any non-permanence issues. If ARB were to adopt any other protocols or apply the current protocols to other locations, ARB would conduct a new rulemaking, in which ARB could amend the rules in the regulation, if it was determined to be necessary.

M-156. Comment: CARB should consider expanding the use of the buffer pool mechanism to include all agricultural and terrestrial sequestration projects, as well as other offset types. (EDF1)

> **Response:** Currently the only sequestration project types included in the regulation is Compliance Offset Protocol, U.S. Forest Projects and Compliance Offset Protocol, Urban Forest Projects. Any additional protocols would need to be adopted as part of a separate regulatory process that meets the requirements of Administrative Procedure Act. If we were to adopt any agricultural and terrestrial sequestration protocols, we would consider the appropriate mechanisms to ensure permanence and discuss it with stakeholders through the public process.

Early Action

Early Action Operations

M-157. (multiple comments)
Comment: ARB should clarify when the ARB offsets program will be operational. Many offset project developers will want to know when the ARB offsets registry will be operational, which will affect their decision of whether to register a project with ARB versus other registries. Any information you can provide on when ARB will be ready to make decisions on early action credits and to register offsets under the ARB protocols would be very helpful. (CERP1)

Comment: Finite Carbon is actively verifying forest carbon projects to the Climate Action Reserve Protocol 3.1 and 3.2. In order to effectively plan verifications and sales, we would like ARB to publish a draft timeline of when the Compliance Protocols will be available for use. We also feel that clarity on the exact mechanics of transferring a project from the Climate Action Reserve to ARB is critical to keep continuity in the carbon market. (NISSENBAUM)

> **Response:** The regulation includes provisions to allow early action offset credits to be credited as ARB offset credits and used in the cap-and-trade program. We included these provisions to allow parties to develop offset projects and purchase offset credits that are being issued by Early Action Offset Programs. These provisions will provide parties with certainty that the regulation will allow them to participate in the offsets market while ARB finalizes the regulation and takes the necessary implementation steps to develop a fully functioning ARB offsets program and offsets tracking system. Once ARB Compliance Offset Protocols are finalized in October 2011, project developers will be able to use them to quantify, monitor, and report their GHG reductions and GHG removal enhancements. In 2012, we anticipate that the Board will consider and approve additional Offset Project Registries so that project developers can list and report their emissions with these registries. We will also accredit ARB offset verifiers to

verify GHG reductions and GHG removal enhancements from offset projects developed under Compliance Offset Protocols.

In addition we added new section 95990(k) to the regulation, to clarify how early action offset projects transition to Compliance Offset Protocols.

M-158. Comment: Under section 95990(b), it is not clear as to whether a project must simply use the CAR "offset quantification method" or whether the project must also successfully list and register credits as CRTs on the CAR Registry. Given that the CAR Registry does not currently have the capabilities listed in section 95990(c) nor the capabilities listed in section 95986(d), it is not obvious how projects using these protocols qualify under this section. Clarifying language should be added. (TPI2)

Response: Original section 95990(b), now new section 95990(c), lists the criteria that the early action offset credit, or GHG reduction or GHG removal enhancement must meet to be issued ARB offsets pursuant to section 95990(i). One of the requirements in section 95990(c)(3) is that the offset project has to be listed or registered by an Early Action Offset Program. The listing requirements for early action offset projects can be found in section 95990(e). An Early Action Offset Program is defined in section 95802, and means a program that meets the requirements of section 95990(a) and is approved by ARB. We believe there are programs that would meet the requirements and could be approved as Early Action Offset Programs.

Early Action Offset Supply and New Early Action Protocols

M-159. Comment: ACR is now submitting three offset protocols for potential approval under Subarticle 14 of the proposed regulation – either added to the list of recognized quantification methodologies for Early Action Offset Credits in section 95990(b)(5), or approved under "Third-Party Offset Programs for Purposes of Accepting Offset Credits for Early Action" in section 95990(c). These protocols are additional to those currently represented in section 95971 and Parts II through V of the regulation as Compliance Offset Protocols, and to those currently listed in section 95990(b) as Early Action protocols. The three ACR-approved protocols are listed below (NOTE: 3 protocols (attachments) also submitted with this comment- see comment 509 - MARTINN)

1. Nitrous Oxide (N_2O) Emission Reductions through Changes in Fertilizer Management. Applicable to agricultural land management project activities that involve a change in fertilizer management including changes in fertilizer rate, type, placement, timing, use of timed-release fertilizers, use of nitrification inhibitors, and other factors.

2. Conversion of High-Bleed Pneumatic Controllers in Oil and Natural Gas Systems. Details requirements for oil & gas companies to earn offsets by reducing fugitive emissions of methane through retrofitting existing high-bleed pneumatic controllers with low-bleed options.

3. Improved Forest Management (IFM) through Increased Forest Carbon Sequestration. Quantifies GHG emission reductions resulting from a long-term commitment to increase forest carbon sequestration over baseline forest management practices, on privately owned timberlands exceeding 1,000 acres in the United States.

ACR and its parent organization, Winrock International, request these protocols be listed as "under review" in section 95990(b)(5) or where appropriate in the regulation, and to provide ACR with a schedule for their review in 2011. Beyond the three protocols listed above, ACR offers for ARB's consideration the following additional protocols that we expect to be completed in 2011:

1. Livestock Manure Management. Provides requirements for the quantification, monitoring, and reporting of GHG offsets from dairy cattle and swine manure management systems. Developed in California with the support of the California Energy Commission, Inland Empire Utilities Agency, South Coast Air Quality Management District, and other stakeholders. ACR is also exploring the potential for simplified methodologies for small-scale livestock facilities, for which existing protocols are generally not cost-effective. (Expected availability: first half 2011)

2. Restoration and Preservation of Coastal Wetlands. This methodology for afforestation, reforestation and revegetation of wetlands is applicable to degraded deltaic wetlands experiencing geological subsidence where hydrology is being restored to increase wetland productivity leading to additional carbon sequestration as a result of freshwater, nutrient, and or sediment addition. (Expected availability: first half 2011)

3. Improved Grazing Land Management. This holistic grazing methodology will address changes in soil carbon sequestration, changes in emissions from enteric fermentation and manure application, and emissions from fertilizer use. (Expected availability: first half 2011)

4. Afforestation/Reforestation. This methodology adapts CDM-approved methodology AR- ACM0001 with the addition of guidance on accounting for wood products. (Expected availability: first quarter 2011)

Moreover, ACR methodologies for Reducing Emissions from Deforestation and Degradation (REDD+) internationally will provide an important added option for AB 32 compliance under section 95993. (MARTINN)

Response: We appreciate the submittal of ACR's protocols. A new section 95990(c)(5)(E) is reserved in the modifications to the regulation for new additional early action project protocols. However, approving additional protocols does not fall under the purview of this rulemaking. Any new offset protocols approved for use in the compliance program must be adopted by the Board after undergoing a full regulatory process, including an ARB stakeholder process, in accordance with the Administrative Procedure Act. If ARB were to adopt any additional protocols that could be recognized for bringing in early action offset credits, it would have to be done as part of this separate rulemaking and approval process.

M-160. Comment: The current regulation inadequately addresses early action credit. AB 32 mandates that credit be given to voluntary early action measures. As presently stated in the regulation, it is too limited. More protocols need to be recognized. (COPC2)

Response: We disagree that the regulation inadequately addresses early action. AB 32 states that ARB must ensure that entities that voluntarily reduce their emissions receive appropriate credit. We believe that early action offset program, in addition to other aspects of the cap-and-trade program, such as through the allocation of allowances, sufficiently rewards early movers. In addition to the CAR protocols that we are recognizing in section 95990, new section 95990(c)(5)(E) is reserved in the modifications to the regulation for new additional early action project protocols. All offset protocols used in the compliance program must be adopted by the Board after undergoing a full regulatory process, including an ARB stakeholder process, in accordance with the Administrative Procedure Act. ARB plans to evaluate additional protocols for approval in 2012. As we evaluate additional protocols, we will assess whether or not early action offset credits should be allowed from those project types.

M-161. Comment: COPC appreciates that CARB seeks to meet the AB 32 requirement that it give credit to early voluntary reductions in GHGs. However, COPC believes that CARB has failed to give "appropriate credit" to many early reductions in GHGs by limiting its recognition of early action offsets to those generated under four Climate Action Reserve ("CAR") protocols (see section 95990(b)(5)). While the four CAR protocols expressly recognized for Early Action credit in the Regulation have indeed guided the generation of high-quality offsets, there are other protocols developed both by CAR and by other organizations such as the Voluntary Carbon Standard Association (VCS) and the American Carbon Registry (ACR) that also have guided the development of voluntary offsets that are just as real, additional, permanent, unique and verifiable as those developed pursuant to the four chosen CAR protocols. COPC also notes that by recognizing only protocols generated by one third party and not any of the others currently operating in the voluntary market, CARB is sending the wrong signals. It risks appearing to prefer one NGO over another for little apparent substantive reason. In addition, it exposes CARB to the risks inherent in relying only on one organization. Finally, if CARB does not expand the number of eligible early action protocols, there is a strong possibility that there will be a shortage in the supply of available offsets in the initial phases of California's Cap and Trade program. To ensure that the price of AB 32 compliance does not rise unnecessarily, CARB should expand the number of protocols expressly recognized in the regulation under which early action offsets may be generated. (COPC1)

> **Response:** We disagree that the regulation inadequately addresses early action. AB 32 states that ARB must ensure that entities that voluntarily reduce their emissions receive appropriate credit. We believe that early action offset program, in addition to other aspects of the cap-and-trade program, such as through the allocation of allowances, sufficiently rewards early movers.
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> In addition to the CAR protocols that we are recognizing in section 95990, new section 95990(c)(5)(E) is reserved in the modifications to the regulation for new additional early action project protocols. All offset protocols used in the compliance program must be adopted by the Board after undergoing a full regulatory process, including an ARB stakeholder process, in accordance with the Administrative Procedure Act. The protocol approval and public process convened by a voluntary program, such as CAR, cannot substitute for a stakeholder process conducted by ARB for rulemaking purposes.
>
> ARB plans to evaluate additional protocols for approval in 2012. As we evaluate additional protocols, we will assess whether or not early action offset credits should be allowed from those project types. In approving additional protocols ARB is looking at protocols developed by any third-party, including other voluntary and regulatory offset programs.
>
> We do not agree that there will be insufficient offset supply in the first compliance period. We estimate that if every entity used their allowable eight percent offsets, approximately 26 million metric tons of offsets would be needed in the first compliance period. This reduced need is due to a start of the first compliance period in 2013 instead of 2012. At this time, based on the four offset protocols the Board has endorsed—manure digesters, forestry, urban forestry, and destruction of ozone depleting substances— ARB will be close to the supply demand for the first compliance period. We also will consider additional Compliance Offset Protocols beginning in 2012.

M-162. (multiple comments)
Comment: Early action is recognized under section 95990 by allowing entities to use for compliance with the cap and trade program offsets issued under four CAR protocols. While this is helpful, the number of CRTs generated under those four protocols is limited. Rather than allowing only a restricted set of CRTs to be used for compliance as early action credits, ARB should allow broader use of CRTs. There is no reason not to allow a broader use of CRTs on an ongoing basis as well as to recognize early action. (SCPPA2)

Comment: Similar to eligible project types starting in 2012, CARB has limited early action credits. By only allowing Climate Action Reserve credits issued under Forestry, Livestock, Urban Forestry, and ODS protocols, CARB, is hampering its ability to contain costs in the early years since there are few CAR credits currently issued under those protocols. CARB should encourage early investment in offset projects by expanding its eligible early action credits to include landfill and coal mine projects, and to allow credits from other scientifically rigorous registries such as the Voluntary Carbon Standard and the America Carbon Registry. (CE2CP)

Comment: If offset supply falls short of demand, the fact that the few available offset projects are well-qualified and additional will be little consolation in comparison to the financial burden. As a result, the regulatory system as a whole may be endangered, putting pressure on the Board to ease the cap explicitly – exactly the situation we would all like to avoid. Therefore we believe it is critical to ensure an adequate supply of offsets throughout the first compliance period, to the extent this can be done within the established emissions cap. Therefore, we recommend that ARB expand the Early Action offset protocols accepted to include the CAR Landfill Project Protocol as soon as can possibly be achieved. In short, we see substantial benefit to including the CAR landfill methane protocols and no downside from a policy standpoint. We believe a fast-track process, such as one parallel to the final adoption of the cap and trade regulation, would do much to ensure the launch of a regulatory system in 2012 which is both environmentally and economically sound. (TPI1)

Comment: Expand the eligibility for early action offset credits to non-CAR domestic and international programs. We strongly believe that other offset programs, regulating domestic and international offsets, maintain equally high standards of environmental integrity. Restricting eligible early action offset credits to CAR seems arbitrary and may lead to the under supply of the market in crucial early years. IETA urges ARB to consider approving existing protocols/methodologies under other domestic and international offset programs like the Voluntary Carbon Standard and the Gold Standard for acceptance as early action offsets in the California cap and trade system. (IETA1)

Comment: CERP supports ARB's decision to bring early action credits into the program from the four specified project types and ARB's decision not to limit early action to California projects. These were important first steps to generate early supply. Yet, these steps will not generate a substantial quantity of offsets. More will be needed. CERP encourages ARB to expand early action eligibility to other Climate Action Reserve (Reserve) protocols, including landfill methane, and to protocols from other well-respected offset registries. In particular, landfill methane capture projects should be included. Whatever concerns ARB has about having a chilling effect on landfill regulations in other jurisdictions are not relevant to the early action program, which recognizes projects that are already ongoing or will begin in the very near-term. Making such projects eligible for the early action program can have no negative effect on regulatory decisions in the host jurisdictions. It will, however, encourage widespread adoption of methane capture technologies at unregulated landfills, a highly efficient means of reducing GHG emissions. (CERP1)

Comment: The Council encourages the Air Resources Board to facilitate offset supply by approving additional protocols, both for development of compliance offset protocols under section 95971 and for Early Action Offset Credits in section 95990(b). Considering the timeframe required for protocol approval, California Environmental Quality Act (CEQA) review, offset project development and verification, this process should begin immediately and be as streamlined as feasible in order to ensure that adequate offset supply is available at the start of the first compliance period in 2012. (BCFSE)

Response: In addition to the CAR protocols that we are recognizing in section 95990, new section 95990(c)(5)(E) is reserved in the modifications to the regulation for new additional early action project protocols. All offset protocols used in the compliance program must be adopted by the Board after undergoing a full regulatory process, including an ARB stakeholder process, in accordance with the Administrative Procedure Act. The protocol approval and public process convened by a voluntary program, such as CAR, cannot substitute for a stakeholder process conducted by ARB for rulemaking purposes.

ARB plans to evaluate additional protocols for approval in 2012. As we evaluate additional protocols, we will assess whether or not early action offset credits should be allowed from those project types. In approving additional protocols, ARB is looking at protocols developed by any third-party, including other voluntary and regulatory offset programs.

We do not agree that there will be insufficient offset supply in the first compliance period. We estimate that if every entity used their allowable eight percent offsets, approximately 26 million metric tons of offsets would be needed in the first compliance period. This reduced need is due to a start of the first compliance period in 2013 instead of 2012. At this time, based on the four offset protocols the Board has endorsed— manure digesters, forestry, urban forestry, and destruction of ozone depleting substances—ARB will be close to the supply demand for the first compliance period. We also will consideration additional Compliance Offset Protocols beginning in 2012.

M-163. Comment: Clarify the early action provisions. Section 95990(b) of the draft regulation suggests that no additional offset project types will be able to be added to the list of creditable early action offsets. This section should provide a mechanism for adding to the list of eligible early action offset project types and protocols to incentivize the development of early action offset projects now and the creation of early action offsets. VCSA recommends the recognition of project-based approaches to reducing emissions during a transitional phase that closely mirrors the early action stage of the program. This change would ensure an adequate supply of offsets for the program. (VCS)

Response: In addition to the CAR protocols that we are recognizing in section 95990, new section 95990(c)(5)(E) is reserved in the modifications to the regulation for new additional early action project protocols. All offset protocols used in the compliance program must be adopted by the Board after undergoing a full regulatory process, including an ARB stakeholder process, in accordance with the Administrative Procedure Act. ARB plans to evaluate additional protocols for approval in 2012. As we evaluate additional protocols, we will assess whether or not early action offset credits should be allowed from those project types. We will also assess whether other protocols for the four project types for which we have already approved early action protocols should be included in the early action offset program.

M-164. (multiple comments)
Comment: ARB should consider as early a start date as possible for qualifying offset projects, ideally in advance of when commitments for emissions reductions would begin. Emitters subject to compliance requirements who offset emissions voluntarily using protocols/methodologies already approved by ARB in anticipation of the start of compliance should be incentivized in a concrete fashion. (SUNONESOLUT)

Comment: For early action credits, we have a technology company that has LEED buildings and high energy efficiency equipment. They have built cogeneration. Now they are unsure whether they will get full credit under this regulation for what they've done and how it will affect their expansion plans in the future. (INDENVASSOC)

Response: The regulation includes rules to recognize early voluntary actions in section 95990. We are allowing early voluntary actions to be recognized for certain offset project types listed in section 95990(c)(5). The regulation stipulates that offset credits cannot be generated for activities that reduce emissions in capped sectors. The electricity sector is a capped sector under this program. If ARB were to also issue offset credits for those reductions, the reductions would be double-counted within the cap-and-trade program. Therefore, offset credits can only be issued for activities that are not capped.

Early Action Offset Project Eligibility

M-165. Comment: CARB should allow high quality offsets regardless of their vintage. CARB should recognize early action offsets generated prior to January 1, 2000. So long as the credits are real, additional, verifiable, unique and permanent, there is no reason to prevent the use of high-quality offsets generated prior to 2005. As drafted, the regulation would perversely penalize the earliest developers of offsets instead of rewarding them for pioneering cost-efficient and vitally important GHG reduction strategies. Exclusion of these high quality offsets also will reduce the overall volume of quality offsets available to the market, thereby hindering the overall effectiveness of the program. Rather than drawing a line at January 1, 2005, COPC recommends that CARB simply hold older offsets to the same standards of quality and verifiability as newer offsets. If, however, CARB concludes that a threshold date is necessary, it should move the date back to no later than January 1, 2001, to maintain consistency with recent federal cap and trade efforts. (COPC1)

Response: The regulation includes a process for accepting offset credits from qualified existing offset projects into the ARB compliance offsets program, to help create an initial supply of offset credits for the cap-and-trade program. We do not agree with the January 1, 2000, date proposed by the commenter because beginning in 2005, the Climate Action Reserve (CAR) and its predecessor, the California Climate Action Registry, began adopting voluntary GHG accounting protocols to encourage voluntary early action to reduce GHG emissions. To ensure the GHG reductions and GHG removal enhancements being used in the compliance program are real and additional, we chose to implement the January 1, 2005, date to correspond with the adoption of voluntary offset protocols as the eligible date for transition of early action offset credits to ARB offset credits.

M-166. Comment: The proposed regulation limits early-action compliance vintages to 2005-2014. The justification for the earliest vintage to be 2005 is that it is the first year Climate Action Reserve offset protocols were available for verification. This justification is arbitrary for the following reasons:

a. Although it was the first year the Climate Action Reserve protocols were available for verification, there is nothing in the ARB regulation which limits early-action criteria to Climate Action Reserve projects only. Another registry which may be approved by ARB may have had its first protocol available for registration in 2002 or 2004 or any of a number of dates;
b. While 2005 is the year in which the protocols were first available to be used for verifications, the Climate Action Reserve Protocols allow for projects to receive verified CRTs as far back as 2001; and
c. The early action criteria do not have a cut-off for early start dates. Therefore, a project may start in 2001 but its 2001-2004 vintages would not be considered compliance-grade while its 2005 vintages are. There is no scientific or policy reason that a 2004 vintage offset and a 2005 vintage offset from the same project do not constitute equal quality emissions reductions. Forest carbon projects in particular are adversely impacted by this provision. Forest carbon offset projects tend to have a significant number of offset credits issued in the first year of the project with annual offsets issued to a much lesser extent. If a project were to have a start date of 2001, the majority of the project offsets would come at that time. If 2001 vintages are excluded as compliance offsets, they will lose significant value in the market and make it difficult if not impossible for the project to pay for the 100+ year compliance costs let alone the opportunity cost for foregone harvest. Of the 46 forest carbon projects listed on the Climate Action Reserve, 18 have pre-2005 start dates. We recommend that ARB revise the early action vintage date to 2001 which corresponds to the signature of California Senate Bill No. 527 so that the justification is rooted in a California precedent and is not specific to an independent registry which may be one of many ultimately approved. (NISSENBAUM)

Response: In response to comment "a.": For projects developed under CAR protocols we believe that January 1, 2005, is the appropriate date to credit the early voluntary GHG reductions and GHG removal enhancements because it reflects the time frame in which the voluntary protocols were approved by CAR. If ARB decides to accept early action offset credits achieved under other protocols not developed by CAR, ARB will evaluate whether another date is appropriate for those credits and amend the regulation if necessary.

In response to comment “b.”: ARB cannot rely on the rules of a non-regulatory program or rely on such program to perform regulatory verification of offsets that will be used for compliance. AB 32 requires that all offset credits used for compliance be based on the result of regulatory verification.

In response to comment “c.”: For reasons mentioned in response to comment “a.” we believe that January 1, 2005, is the appropriate date to begin crediting voluntary reductions as compliance if they meet the requirements of section 95990. Pre-2005 vintages can still be sold in the voluntary market but may not be used for compliance.

M-167. Comment: Section 95973 states that for an offset project to be eligible under the ARB Forest Protocol it must have a project commencement date after 12/31/06. There are many projects registered with CAR, including our Garcia River Forest project, that have commencement dates prior to 12/31/06. As written, this provision suggests that while these projects will quality for early action under Subarticle 14, they will not be eligible for eventual registration (and a renewed crediting period) under the ARB Forest Protocol. It seems unlikely that this is what staff intends and it would likely discourage early action projects from participating in the compliance program. One way this can be corrected is to add the following italicized language to 95973(a)(2)(B) at page A-113: “(B) the Offset Project commencement date occurs after December31, 2006 or the Offset Project meets the requirements of section 95990(b).” (TCF)

Comment: There are numerous uses of the term "Commencement date in the protocol, all of which make sense if the Regulation is modified to recognize early action projects that meet ARB qualifications can have earlier commencement dates governed by the start date limitations as set forth in the ARB approved early action protocols. An example of this problem is: All ARB offset projects must have a "Commencement Date" of January 1, 2007 or later. This is a significant problem for early action CAR reforestation projects which were allowed to have "Start Dates" back to January 1, 2001. ARB should not be overly concerned about this Reforestation start date issue as this is the same commencement issue and these projects do not accrue significant offset credits during the four year period between 2001 and 2005 (the earliest early action offset credit that can qualify as a compliance grade offset under ARB). Also both CAR v 3.2 and the ARB protocol say that Reforestation projects can't receive credits until after the second verification which in almost all cases has not happened yet. (CAFORESTRYASSOC1, CFA)

Comment: After December 31, 2014, CAR projects must be re-verified and brought up to ARB protocol standards. There is an inconsistency with this requirement and Early Action Projects, especially around the limits on Commencement Date in the regulations which could prevent early action projects from being re-verified. (CAFORESTRYASSOC1, CFA)

> **Response:** We agree and added a new section 95973(c) that allows a commencement date prior to 2006 for early action offset projects that transition to Compliance Offset Protocols pursuant to section 95990(k).

M-168. Comment: The restriction in section 95990(b)(1) of early action credit to removals that occurred between January 1, 2005, and December 31, 2014, and the requirement in section 95973(a)(2)(B) that forest projects under the ARB compliance offset protocol begin after December 21, 2006, are arbitrary to the extent that such a policy fails to credit forest sequestration accomplished prior to 2005. The rationale provided by ARB —that 2005 is the date that "offset projects began verifying their GHG reductions... based on the protocols approved in this section" (ISOR at IX-171)—is insufficient and illogical for several reasons. First, the Climate Action Reserve ("CAR") forest protocol, upon which the ARB Forest Protocol is based, itself credits reductions from 2001. [See California Air Resource Board, Proposed Regulation to Implement the California Cap-and-Trade Program, Part V, Staff Report and Compliance Offset Protocol, U.S. Forest Projects, Preamble ("Forest Protocol") at five ("ARB used CAR's Forest Project Protocol Version 3.2 as the basis for transitioning to a compliance program").] Indeed, of the 46 forest carbon projects listed on CAR, 18 have pre-2005 start dates.

Second, numerous meritorious forest projects have been started under other protocols such as the American Carbon Registry ("ACR") and Voluntary Carbon Standard ("VCS") which credit reductions prior to 2005 (moreover, as discussed below, ARB's decision to credit only CAR protocols is itself arbitrary, unjustified and discriminatory).

Third, as ARB acknowledges, California Senate Bill 812 expressed the intent of the California legislature to promote and credit early action in forestry projects at least as early as 2003, and as early as 2001, Senate Bill 527 expanded the functions of the already-existing California Climate Action Registry to recognize emissions reductions stemming back to 1990. Similarly, ARB's statement that forest projects must switch to ARB protocols by December 31, 2014, a date which corresponds to the end of the first market compliance period, ISOR IX-171, fails to discuss the penalty imposed on early action forest projects commenced prior to that date.

Further, as a matter of environmental policy and review, ARB has failed to consider that disqualifying early-mover projects will likely result in the abandonment of those projects, thus not only increasing greenhouse gas emissions but also losing the other societal benefits provided by forest conservation projects, such as habitat and watershed protection. Although ARB recognizes its duty under AB 32 to consider "overall societal benefits, including reductions in other air pollutants...and other benefits to the economy, environment and public health," ISOR at II-51 (citing Health & Safety Code 38562(b)(6)), the Agency has failed to justify why its arbitrary date restriction is defensible in light of AB 32's mandate or why an earlier start date is not an acceptable alternative. (FCC, BLUESOURCE)

Response: We disagree that we have not met the requirements of AB 32 in regard to recognizing early actions as appropriate. The regulation includes a process for accepting offset credits from qualified existing offset projects into the ARB compliance offsets program. This not only recognizes and rewards these actions, it also helps create an initial supply of offset credits for the cap-and-trade program. We do not agree with accepting offsets from projects before 2005 because beginning in 2005, the Climate Action Reserve (CAR) and its predecessor, the California Climate Action Registry, began adopting voluntary GHG accounting protocols to encourage voluntary early action to reduce GHG emissions. To ensure the GHG reductions and GHG removal enhancements being used in the compliance program are real and additional, we chose to implement the January 1, 2005, date to correspond with the adoption of voluntary offset protocols as the eligible date for transition of early action offset credits to ARB offset credits.

That said, early action offset projects that began prior to 2005 are still allowed to come into the compliance program and receive early action offset credits for reductions that they achieve between 2005 and 2014. To clarify this point we added a new section, 95973(c), that allows a commencement date prior to 2006 for early action offset projects that transition to Compliance Offset Protocols pursuant to section 95990(k). Any reductions achieved before 2005 may still be traded and sold in the voluntary market but will not be recognized by ARB or allowed to be used for compliance.

In response to the commenter's second point, for projects developed under CAR protocols, we believe that January 1, 2005, is the appropriate date to credit the early voluntary GHG reductions and GHG removal enhancements because it reflects the time frame in which the voluntary protocols were approved by CAR. If ARB decides to accept early action offset credits achieved under other protocols not developed by CAR, ARB will evaluate whether another date is appropriate for those credits and amend the regulation if necessary.

In response to the commenter's third point, we added new section 95990(k) to clarify how early action offset projects transition to Compliance Offset Protocols. New section 95990(k)(2) clarifies that once an early action offset project transitions to a Compliance Offset Protocol it will begin an initial crediting period. The crediting period under the early action offset program does not count under the compliance offset program, so the early action offset project may transition any time before February 28, 2015, but must list or register with an Early Action Offset Program by January 1, 2014, (section 95990(c)(3)) to get early action offset credits. This provides a seamless transition process for early action offset projects and guarantees them a new crediting period. It is necessary for offset projects beginning February 28, 2015, to transition to Compliance Offset

Protocols to ensure consistency in the program. It is also necessary that all offset projects are following the rules of the regulation, including the rules in the Compliance Offset Protocols. We believe that this process will incentivize early action offset projects to transition to Compliance Offset Protocols, and that it will not penalize them.

M-169. (multiple comments)
Comment: The draft regulation proposes that ARB accept Early Action offset credits from three sets of CAR protocols that allow projects with startup dates as early as January 1, 2001, and even earlier in the case of some forestry projects. In doing so, ARB relies on CAR's assessment of additionality in the context of their protocol development work. However, CAR's definition and application of additionality has changed over time, especially with respect to forestry projects; consequently, the additionality standard applied to these early action projects is internally inconsistent and generally inconsistent with ARB's stated aims, as explained below.

According to the proposed ARB regulatory language, a project is additional if we cannot reasonably expect it to have occurred without financial incentives provided by carbon credits. By contrast, according to CAR's protocol for Conservation Based Forest Management version 2.1, a project is additional if it can demonstrate that the project's carbon sequestration activities exceed the project baseline sequestration projection (which is generally defined as management per the Forest Practices Act and could be set backwards as early as 1990), without reference to commencement date, financial requirements or incentives. Later versions of the CAR protocols establish a "no earlier than" date of January 1, 2001 in line with the creation of the California Climate Action Registry that same year. However, no other filters are applied to ascertain whether projects with historic start dates were in fact influenced by carbon revenue. In Fall 2009, CAR's Board of Directors recognized that the January 2001 start date criterion was problematic: "Although the creation of CCAR may have signaled the prospects for participating in a carbon market in 2001, the notion that a developer might have started a truly "additional" project at that time and then waited for nearly nine years to apply for formal registration with the Reserve is increasingly difficult to accept." The Board addressed this concern by adopting new rules and imposing supplementary additionality screens, but these were not applied retroactively to projects already listed. Based on TerraPass detailed factual assessments of a great many offset projects commenced in the first half of this decade, we believe a disproportionate share of these early projects were developed with no reference to or influence from the prospect of carbon revenue, even if speculative or distant. We comprehend that there are countervailing policy aims that may contribute to a decision to set aside the regulation's additionality rules for these early action projects. First, it may be appropriate to provide special consideration for project owners who acted early and purposefully to mitigate climate change impacts even if they did not anticipate a financial benefit for doing so. Second, ARB may be concerned about launching a new cap and trade system without the full complement of economic controls which a well-supplied offset market would provide. Regarding special consideration, we hasten to point out the voluntary offset marketplace has been in place and active in the US for half-a-dozen years. Early actors have had the opportunity for financial reward throughout this period thanks to early protocol development by the California Climate Action Registry, the Chicago Climate Exchange, and others. We believe it is reasonable to ask whether any further special consideration, as applied to non-additional projects in a regulatory context, is an appropriate public policy goal for the State of California. That said, we believe that appropriate recognition can be given to early actors and sufficient supply achieved without sacrificing the emissions cap. Offsets' primary purpose in the proposed cap and trade system is to enable regulated emitters to achieve the required emission reductions at a lower overall cost than would be possible if they were limited to reductions achievable within the regulated community itself.

To the extent that a well-supplied marketplace can be achieved with real, additional emission reductions, the program's goals will be well-served. TerraPass recommends that a simple additionality screen be required of all projects with commencement dates earlier than January 1, 2007, in order to better distinguish those which are additional from those which are not. Specifically, we recommend that ARB limit the maximum allowable length of time between: 1) a project's commencement date (generally, this is the online date or the start of the emission reduction/sequestration activity); and 2) the date upon which the project owner committed the project (in writing) to a carbon registry. Note, we are referring to a commitment to any carbon registry; though the Early Action credits will only come from one registry such as CAR, the project's initial commitment may have occurred many years earlier on a different registry.

In our experience, early project owners who were influenced by carbon revenue and/or by the pressing need to mitigate climate change are the very same early actors who pioneered the Chicago Climate Exchange and the California Climate Action Registry. Furthermore, these same people acted quickly and diligently to quantify and verify their activities so as to prove the promise of this new mitigation possibility. Also, simple logic and common sense dictates that if a project would not have occurred but for carbon revenue, that the project owner would seek out such revenue within a reasonably short timeframe. This simple logic has proved powerful enough that many carbon standards now impose registration time limits on both historic and new projects as an additionality test. Indeed, a "time limit screen" is precisely the technique adopted by the Climate Action Reserve Board in 2009 when it changed its eligibility rules so as to assure project additionality. Similarly, the Voluntary Carbon Standards Association imposes a maximum time limit between project startup and third-party Validation – and has done, since 2007. ARB is fortunate to be able to take best practices from the experiences of voluntary registries. In this case, these time limit screens are a widely used and agreed-upon best practice. To forego this practice would be to take a significant and unnecessary step backward. The time bounds of this screening tool (its endpoints) can be set using any number of dates in a project's lifecycle. The endpoints we recommend above are easily verifiable, and similar to endpoints used by CAR today. It's important to remember, though, that for early projects these dates will be a reflection of both the intentions of the project owners, and the practical availability of a registry to engage with. Neither the California Climate Action Registry nor the Chicago Climate Exchange, were available generally before 2004. For this reason, we recommend that the maximum time limit chosen for this screen be longer than that used by CAR and the VCS. While these two bodies use 24-month limits; we recommend a three-year limit for application to these Early Action projects. We have applied this screen to many CAR projects for which we have done substantial supplemental, project-specific research, and believe it's extremely effective and produces very few errors. Additional projects pass the screen. Non-additional projects do not. (TPI1)

Comment: Section 95973(a)(2)(B) limits ARB-issued offset credits to projects with a commencement date later than December 31, 2006. The Initial Statement of Reasons notes that this date is consistent with AB 32's passage, and projects allowed as a result are more likely to have been inspired by California's global warming legislation. However, the regulation's definitions of "additionality" and "business-as-usual" specify that the project should not have occurred but for the possibility of carbon revenue, not that such carbon revenue must have been a result of California's actions. Indeed, such a definition would limit potential offset projects to a very small pool as the revenue from California markets is still uncertain and until about a month ago was assumed to be zero due to various legal and political threats. We agree that a timing test should be applied to offset projects to assure additionality, but consistent with the stated definitions of additionality and business-as-usual, we recommend that this test take the form of a time limit instead of a cut-off date. A time limit test examines the length of time between the project's commencement and its commitment to a carbon revenue regime. Most voluntary registries use this type of test. It has the distinct advantage of always being "current," which is to say, it provides a moving time window instead of a fixed date in time that quickly become ineffective as an additionality screen as years go by. Our earlier comments on the Early Action Projects describe how this type of test works, and makes a specific recommendation for the test language. We echo those recommendations here, and suggest that this test is a superior means of assuring additionality for all projects over time than imposing an arbitrary cut-off date. (TPI2)

> **Response:** We disagree that a timing test is needed for early action offset projects. At the time of initial crediting in the voluntary program, the early action projects had to meet the additionality requirements of the voluntary offset protocol and the early action program. Once an early action offset project transitions to ARB, it must meet the additionality requirements of the Compliance Offset Protocol and regulation. We believe the early action credits that would be eligible to be issued ARB offset credit for the early action protocols are additional.
>
> In addition, we added a requirement that Offset Project Operators or Authorized Project Designees must submit their first Offset Project Data Reports within 24 months of listing their offset project (section 95976(d)), to further address these concerns.

M-170. (multiple comments)
Comment: The regulation neglects to require that projects coming from third party programs be additional. This is simply a mistake. And we hope it can be corrected in the 15-day comments. The most immediate effect of this error is that the large volume

of non-additional projects will be welcomed into the program as part of the early action provisions. This can be easily corrected. We know that there is a lot of pressure to put more offset supply into the program, especially in the early years. We agree that a fully supplied program is a good thing. However, you can do this without compromising the cap by allowing non-additional offsets into the program. This can be our accomplished with two small additions to the regulation. The first is to apply an additionally screen, which is already used by most voluntary offset programs today to early action projects. And the second is to allow additional protocols, which I know you're planning to do. In particular, we support the landfill methane protocol. That is one of the most effective offset protocols available. (TPI4)

Comment: Subarticle 14 fails to require fundamental tenets of quality for offset credits: real, additional, quantifiable, permanent, verifiable and enforceable. This oversight should be corrected. Please see our earlier comments regarding a timing test for additionality, including a test applied to all projects which commenced prior to 1/1/2007 if not all projects without exception. (TPI2)

> **Response:** We disagree that that the early action offset projects are not additional. At the time of initial crediting in the voluntary program, the early action projects had to meet the additionality requirements of the voluntary offset protocol and the early action program. Once an early action offset project transitions to ARB, it must meet the additionality requirements of the Compliance Offset Protocol and regulation. We believe the early action credits that would be eligible to be issued ARB offset credit for the early action protocols are additional.

Early Action Offset Project Transition

M-171. Comment: Early action projects should have the option to transition to compliance offset projects in the short-term and at the conclusion of the Early Action crediting period in 2014. Section 95975(g) of the cap and trade regulation implies that a project cannot seek a renewed crediting period earlier than 18 months prior to the expiration of the crediting period. We recommend that early action projects be permitted to transition into compliance projects as soon as possible. When transitioning early action CRTs to compliance credits, one consolidated verification should suffice for all previous vintage years. For future vintages, ARB and CAR verification requirements should be coordinated to only require one verification. (PFT1, PFT2)

> **Response:** We agree that early action projects should have the option to transition to compliance offset projects, and we made several modifications to the regulation to facilitate this process while still ensuring the integrity of the offsets. New section 95990(k) was added to clarify how early action offset projects transition to Compliance Offset Protocols. New section 95990(k)(2) clarifies that once an early action offset project transitions to a Compliance Offset Protocol it will begin an initial crediting period.

We modified section 95990(f) to streamline the regulatory verification process for early action offset credits. Any verifications conducted under a voluntary program, such as CAR, cannot be substituted for the regulatory verification of reductions used for compliance.

M-172. Comment: The requirement in section 95990(b)(3) that early action forest projects be commenced before 2012 and the restriction in section 95990(b)(1) denying credit for reductions achieved after December 31, 2014, artificially limit the crediting period of early action forest projects and fail to provide early action credit for legitimate reductions. Most early action forest projects were commenced on the expectation that they would receive credit for greenhouse gas removals through the end of an established crediting period (typically 30 years) under the eligibility rules applicable at that time. ARB's proposed cut-off in 2014 would make sense only if ARB provided a procedure to transition existing projects verified under early-action protocols (such as the CAR protocol as well as ACR and VCS) to an ARB protocol without significant additional cost and without changing the eligibility rules under which the forest project was started, since the financial value (and economic viability) of early action projects depends on the crediting period and eligibility rules under which the project was commenced.

ARB has not yet provided a procedure for such a transition, and without such a procedure, the value given to early action forest projects would be severely diminished since most forest projects do not generate significant carbon reductions until up to ten years into the project and would have relatively little carbon credit accumulated by 2014 despite significant financial investment. Moreover, such a policy would perversely disincentivize projects using hardwood species, which deliver comparatively more co-benefits due to the longer maturation of those carbon stocks. In short, any cut-off deadlines for early action must be linked to the availability of a procedure for transitioning existing early action projects to the ARB Forest Protocol. And, as discussed below, such transition rules cannot impose significant new costs or change eligibility criteria in a manner that would undermine the early action nature of the project as a practical matter. Any contrary rule would be inconsistent with AB 32 and has not been justified either under the APA or CEQA. (FCC, BLUESOURCE)

Response: New section 95990(k) was added to clarify how early action offset projects transition to Compliance Offset Protocols. New section 95990(k)(2) clarifies that once an early action offset project transitions to a Compliance Offset Protocol it will begin an initial crediting period. The crediting period under the early action offset program does not count under the compliance offset program, so the early action offset project may transition to a Compliance Offset Protocol any time before February 28, 2015, but must list or register with an Early Action Offset Program by January 1, 2014 (section 95990(c)(3)). We removed any requirements that restrict the earliest date that early action offset projects must transition to Compliance Offset Protocols. It is necessary for offset projects beginning February 28, 2015, to transition to Compliance Offset Protocols to ensure consistency in the program and that all offset projects are following the rules of the regulation, including the rules in the Compliance Offset Protocols.

M-173. (multiple comments)
Comment: The requirement for an ARB Compliance Offset Project to begin after December 21, 2006 is concerning because it limits early action projects to a single 10-year crediting period. As currently written, after 2014 any project which meets all the criteria to be an early action project will not be able to convert to the ARB Compliance Offset Protocol. This is especially problematic for reforestation projects which do not produce significant offsets until after the first decade of the project. Any sequestration project is unlikely to be economical if it receives only 9 or 10 years of ARB-compliant early action offsets and is then unable convert to the ARB Protocol while still having at least another 110 years of inventory, verification, and monitoring costs ahead of it and no revenue to offset these costs against. Of the 46 forest carbon projects listed on the Climate Action Reserve, 18 have pre-2005 start dates. We recommend that any project which qualifies as early action per section 95990 and also meets the ARB Compliance Offset Protocol U.S. Forest Projects can convert to the Compliance Offset Protocol on or before December 31, 2014. (NISSENBAUM)

Comment: CERP strongly encourages ARB to give projects registered through the early action pathway a full crediting period during which they will be eligible to earn credits and be approved as ARB credits. Specifically, such projects should be eligible to generate offset credits for the duration of their approved crediting period and should be "shielded" against changes of rules or methodologies during the period. Under such an approach, the regulations could provide that a qualifying early action project could have a crediting period that starts no later than January 1, 2014. Without such crediting periods, the early action pathway will not be financially viable and projects will be forced to wait for the ARB offsets program to be fully functional or for a registry to be approved (along with verifiers) before the project can be registered and begin generating emission reductions and offset credits. Apart from the relatively small quantity of emission reductions available through already ongoing projects, the early action program will generate very few additional emission reductions if there is not a full crediting period. There will be a "gap" in offset supply, as project developers and owners wait for the ARB offset program to become operational. (CERP1)

Comment: Early Action projects should be given a full crediting period: Equator supports ARB's plan to bring credits into the program for early action from projects using four CAR project protocols for vintages 2005-2014. This is an important step towards securing adequate supply of offsets for this program. It is essential, however, to ensure that existing and new projects can count on certainty of long term eligibility under ARB. To this end, we strongly encourage ARB to allow projects to have a full crediting period under the protocol and registry that they were originally registered under. (EQUATOR)

> **Response:** New section 95990(k) was added to clarify how early action offset projects transition to Compliance Offset Protocols. New section 95990(k)(2)

clarifies that once an early action offset project transitions to a Compliance Offset Protocol it will begin an initial crediting period. This provides a seamless transition process for early action offset projects and guarantees them a new crediting period.

M-174. Comment: Section 95975(g) states that a project cannot seek a renewed crediting period earlier than 18 months prior to the expiration of its initial crediting period. (See also 95980(c)). Assuming that early action projects are eligible to re-verify under the ARB Forest Protocol, than it appears that early action offset projects will have to wait until June 2013 to do so. We would prefer to register our early action projects under the ARB Forest Protocol sooner than June 2013. More generally, it would seem to be in ARB's interest to allow projects to re-verify under a new protocol at any time rather than only upon expiration of its prior crediting period (on the theory that more projects will be using the most current, and presumably the best, quantification methodology). Section 95990(c) sets out criteria that an offset project registry must meet to issue early action offsets. One of the criteria is that the registry has the capability to track prices (section 95990(c)(2)(C)). CAR currently does not have that capability. If CAR is not eligible to issue early action offsets then there likely won't be any. We are not opposed to price disclosure and tracking per se, but we urge ARB to reconsider this requirement if it will result in disqualifying early action projects from issuing offset credits under Subarticle 14. (TCF)

Response: The rules for early action offset projects are different from offset projects that are developed initially under Compliance Offset Protocols. Early action offset projects must meet the requirements of section 95990 until they transition to Compliance Offset Protocols.

New section 95990(k) was added to clarify how early action offset projects transition to Compliance Offset Protocols. New section 95990(k)(2) clarifies that once an early action offset project transitions to a Compliance Offset Protocol it will begin an initial crediting period. The crediting period under the early action offset program does not count under the compliance offset program, so the early action offset project may transition any time before February 28, 2015, but must list or register with an Early Action Offset Program by January 1, 2014, (section 95990(c)(3)) to get early action offset credits. This provides a seamless transition process for early action offset projects and guarantees them a new crediting period. It is necessary for offset projects beginning after February 28, 2015, to transition to Compliance Offset Protocols to ensure consistency in the program and that all offset projects are following the rules of the regulation, including the rules in the Compliance Offset Protocols.

We also removed the requirement that the Early Action Offset Program must have the ability to track prices to address stakeholder concerns.

M-175. Comment: Re-registration of early action projects with ARB. As currently constructed, projects which commenced after December 31, 2006, but before January

1, 2012, have several choices: they may use CAR protocols and processes to receive credits, subject to regulatory verification on top of CAR verification; they may register with ARB instead; or they may switch from CAR to ARB at some point in the next two years.

Several questions arise for these cases:

- If a project chooses to register directly with ARB and forego any CAR processes, how will ARB handle credits which are created prior to finalized processes for listing, verification, and issuance? For example, if a project commenced in 2009 and ARB's registry is not available until the end of 2011, what are the implications for the 2009 and 2010 credits? Are they unavailable because ARB requires annual verifications?

- If a project chooses to switch its registration to ARB from CAR, does its crediting period re-set at that time, and if so does that re-set count as one of its allowable renewals?

A guidance document or other process guide which clarifies these issues is needed. (TPI2)

Response: The regulation allows offset projects to come into the program directly under Compliance Offset Protocols instead of first registering with CAR and using CAR voluntary offset protocols and then transitioning over to ARB's protocols. ARB has provided a role for Offset Project Registries (OPR) to perform some of the administrative functions of the offset process in the regulation. ARB plans to utilize OPRs in lieu of performing these duties itself in the short-term, and may choose to continue this throughout the program. ARB has not yet determined if and when it would itself perform these roles. Therefore, in the meantime all parties seeking to use Compliance Offset Protocols must go directly to an OPR to list their projects. ARB plans to approve OPRs sometime in 2012. Even if a project commences prior to the date when ARB approves OPRs it can begin collecting monitoring and reporting data from their project and submit them to an OPR. ARB will allow ARB offset credits to be issued retroactively as long as the operator can submit Offset Project Data Reports for the prior years that meet the requirements and the data are verified according to the regulation for those years.

We added language in section 95990(k)(2) to clarify that all early action offset projects which transition to a Compliance Offset Protocol will begin a new crediting period. This provision was included to provide clarity for stakeholders on the length of eligibility for transitioned offset projects. The new crediting period will count as the initial crediting period for the offset project. A non-sequestration offset project may then renew for two more crediting periods. A sequestration offset project has unlimited renewals.

M-176. Comment: CARB has indicated that it will only accept vintages from 2005-2014 as eligible early action credits. This artificially limits the crediting period of early action offset projects and hampers investment. Numerous offset projects were started with the expectation of an already established crediting period that extends beyond 2014. For example, most early action forestry projects were commenced on the expectation that they would receive credit for greenhouse gas removals through the end of an established crediting period (typically 30 years). CARB's cut off only makes sense if there is a clear procedure to transition projects from other program standards to CARB standards without significant additional cost and without changing the eligibility rules under which the project was originally registered. CARB has not yet provided any guidance on such a procedure, and needs to do so in order to encourage early investment in offset projects. Developers need certainty that their credits will seamlessly transfer from current existing protocols to the future CARB program in order to invest time and money. (CE2CP)

> **Response:** New section 95990(k) was added to clarify how early action offset projects transition to Compliance Offset Protocols. New section 95990(k)(2) clarifies that once an early action offset project transitions to a Compliance Offset Protocol it will begin an initial crediting period. The crediting period under the early action offset program does not count under the compliance offset program, so the early action offset project may transition any time before February 28, 2015, but must list or register with an Early Action Offset Program by January 1, 2014, (section 95990(c)(3)) to get early action offset credits. Once the project transitions, it is guaranteed a full initial crediting period, and, in the case of forest projects, is not subject to any renewal requirements.
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> Further, section 95990(k) of the regulation requires projects developed under CAR's forest protocol version 2.1 to recalculate their baseline based on ARB's Compliance Offset Protocol. This provision is necessary to ensure consistency across all forest projects in the compliance program. Early action offset projects developed under the other protocols mentioned in section 95990(c)(5) must transition to the appropriate Compliance Offset Protocol but do not need to change their baselines.

M-177. Comment: Requirements for approval of third-party offset programs should include a requirement to relinquish any reversal liability requirements over third-party offsets approved by ARB for compliance use. Offset sellers that transfer early action credits into the compliance system will need a clear indication of which program they have a liability towards in the event of a reversal. If an approved third-party offset program still tracks offset transactions after the approval by ARB of credits pursuant to section 95990(d), it is unclear from the proposed regulation as drafted whether a landowner would (for example) still be subject to the requirements of the Project Implementation Agreement required by the Climate Action Reserve, and would therefore legally face a double liability in favor of both CAR and ARB in the event of a reversal. We would suggest that ARB add a requirement to section 95990(c) that offset programs relinquish any contractual right to require an action of the forest owner in the event of a forest carbon reversal that affects tonnes approved by ARB for use in the compliance system. (SHILLINGLAW1)

> **Response:** We added a requirement in section 95990(i)(1)(D)(1.) that the Early Action Offset Program transfer all offsets that reside in their buffer account for forestry to ARB, so that ARB may ensure permanence of any offset project in the ARB compliance program. Once the early action offset credits are verified pursuant to section 95990(f) and meet the requirements for early action, ARB will issue ARB offset credits to replace the early action offset credits, and the Early Action Offset Program must permanently remove them from their registry system. This clarifies that ARB has full control over the offset credits that are issued, even for early action purposes, and the Forest Buffer Account. These additional requirements should alleviate concerns that the Forest Owner must replace reversed tons in both programs.

M-178. Comment: ARB must evaluate the additionality of forest projects implemented as early actions. Forest projects registered under earlier versions of the Climate Action Reserve's Forest Project Protocol (version 2) were allowed to define the baseline as essentially the regulatory minimum for the project area. That is, under the previous versions of the protocol, the baseline was even more vulnerable than it is now to manipulation that would allow forest landowners to obtain carbon credit for forest growth that would have occurred under a business-as-usual scenario. If the credits from such projects are to be adopted for use in the Cap and Trade program, those forest projects must be evaluated for additionality. Without performing this evaluation, ARB risks adopting non-additional credits into the compliance program. (CBD1)

> **Response:** To ensure additionality and consistency within the program, ARB is requiring in section 95990(k)(1)(D) that forest projects developed under version 2.1 of the protocol recalculate their baselines based on ARB's Compliance Offset Protocol when they transfer in to the compliance program. This will ensure that any GHG removal enhancements achieved by these projects are additional and meet the AB 32 requirements.

Transitioning Early Action Offset Credits to ARB Offset Credits

M-179. Comment: Evolution Markets believes that the ARB should define in Q1 2011 an administratively simple and non-onerous process for certification of Early Action Credits for compliance. As the market evolves, project developers sell credits to manage risk and generate cash flow. These offsets in many cases have been bought and sold several times since the primary transaction. Therefore, for most projects that have produced eligible CRTs for Early Action Crediting, the CRTs are dispersed in throughout the market amongst many owners. (EVMKTS)

> **Response:** We made modifications to section 95990 to streamline the process for transitioning early action offset credits into ARB offset credits that can be used for compliance. This includes allowing holders/current owners of early

action offset credits to transition them into the compliance program if the project developers do not do so.

M-180. Comment: In the Proposed Regulation Order (Appendix A), under Registration of (Early) Offset Credits by Third Parties, (section 95990), we suggest that there be a provision added so that ARB can make adjustments as needed to the credits that have been issued by an approved third-party offset program. For example, the proposed ODS protocol uses GWPs for HFCs from IPCC's Second Assessment Report, which are slightly different from those used in the CAR protocol. To ensure internal consistency, ARB will need to re-calculate CRTs previously issued by CAR which have not yet been retired and which qualify under the AB 32 protocol. (EOSC1, EOSC2)

> **Response:** The regulatory verification and issuance of early action credits will be based on the version of the protocol that was initially used in the Early Action Offset Program. ARB will not recalculate the number of credits generated based on ARB's Compliance Offset Protocol. However, once the offset project transitions to ARB's Compliance Offset Protocol, it will be issued ARB offset credits based on the calculations in that protocol.

M-181. Comment: Evolution Markets recommends the following: Establish Streamlined Accreditation Process for Verifiers: The first step in ensuring the market's confidence in Early Action Credits is establishing an ARB accreditation program for verifiers. The sooner Early Action Credit owners can re-verify eligible CRTs to ARB-compliance grade, the sooner liquidity and trading will increase in California. Keeping in mind that credits from offset projects can be owned by several entities, the unifying element in an offset project is often the original project verifier. Therefore, Evolution Markets recommends ARB accredit existing CAR-accredited verifiers for offsets in Q12011 so that CRTs can be re-verified to be fully compliance grade. This will allow a seamless and efficient transition from Early Action to ARB certification. (EVMKTS)

> **Response:** The verifier and verification body accreditation program established in the MRR for purposes of emissions reporting has been expanded to include the accreditation of verifiers and verification bodies for offsets. Expanding the accreditation program will involve project type or protocol-specific training for verifiers. ARB anticipates that many of the verifiers currently active at CAR will apply to be accredited under ARB's regulatory verification program.

Regulatory Verification of Early Action Offset Credits

M-182. Comment: The requirement in section 95990(b)(2) that early action forest projects be verified pursuant to section 95990(f) (which requires verification by ARB-accredited verification bodies) is ambiguous, and to the extent interpreted to require re-verification of projects, is unreasonably onerous and imposes an additional expense that has not been justified in the Initial Statement of Reasons. The inherent nature of early action is that well-meaning actors are "out ahead" of regulatory agencies in terms of solving environmental challenges. Many beneficial forest projects were started well

before ARB had itself acted on its mandate in AB 32 to issue rules and regulations. These early projects were verified under programs such as CAR, ACR and VCS, that are legitimate and widely recognized sources of early reductions. Each of these programs requires strict verification and conflict-of-interest procedures.
It is unclear whether ARB is requiring early action projects to re-verify all aspects of its project in order to transition to the ARB Forest Protocol or whether ARB will allow a more sensible approach of conducting a "gap analysis" by ARB staff or accredited verifiers to ensure that the verification under the previous program was consistent with ARB's verification process. In fact, it is highly likely that most of the verifiers that are currently accredited by other programs such as CAR, VCS and ACR are already, or will quickly be, approved under the ARB accreditation program. It would be unreasonable for ARB to retroactively require forest projects to incur additional expense, which in many cases may undermine the economic viability of the projects, or to duplicate auditing functions already done and approved by third-party auditors under strict criteria recognized in the market as rigorous. The ISOR correctly identifies "rigor and validity of offset credits" as the goal of the verification requirements, ISOR at II-45, but ARB provides no justification for the apparent burden of requiring re-verification of projects that have already been approved under early action protocols. ARB acknowledges that it has a duty under AB 32 to "minimize the cost of implementation and compliance and to maximize the overall benefits" of AB 32, ISOR at II-50, but fails to discuss these requirements in the context of early action projects. (Footnote: Health & Safety Code 38562(b)(5) directs ARB to "consider the cost-effectiveness" of its market rules. Similarly Health & Safety Code 38562(b)(7) requires ARB to "minimize the administrative burden" of its market rules).

If ARB does intend to require full re-verification, the additional expense and unintended consequences will thwart the goals of AB 32 by unnecessarily increasing the cost of greenhouse gas reductions. For example, it is unclear whether transitioning to the ARB protocol for already existing projects will require re-calculating the project baseline, resulting, in some cases in different crediting results, which could raise questions about validity of past credits sold from those projects. In other cases, recalculating the baseline could make projects suddenly ineligible, or unable to generate credits; for example, if they have signed a conservation easement, HCP or SHA since their original project registration. In short, early action projects should be grandfathered into the protocol under which they were initially registered.

The ISOR does not discuss the reasons for requiring re-verification, nor is there any indication that the ARB accreditation program is any more stringent, or produces a higher level of integrity, than the verification processes already in place for existing early action projects. Accordingly, rather than re-verification, we suggest that ARB accept forest projects that have been validated and verified under early action protocols (including CAR, ACR and VCS) to transition to the ARB Forest Protocol without further verification, or at the most, undertake a gap analysis to minimize any verification that is demonstrated to be necessary based on established auditing principles. (FCC, BLUESOURCE)

Response: The requirements for regulatory verification must be met to ensure that the early action offset credits meet the requirements in AB 32 that all offsets must undergo regulatory verification. ARB cannot rely on a non-regulatory program to perform regulatory verification of offsets that will be used for compliance, and AB 32 requires that all offset credits used for compliance be based on the result of regulatory verification.

Section 95990(f) was modified to clarify the requirements for regulatory verification of early action offset projects. New section 95990(f)(1) includes new requirements that the verifier performing the regulatory verification services must be different than the one that did the initial verification for the Early Action Offset Program. This ensures that the review is completely independent and unbiased. The new requirements include a desk review of each Offset Project Data Report (new section 95990(f)(3)) by an ARB accredited verification body based on all original early action offset project documentation. This provision was added in response to stakeholder comments to streamline the requirements for regulatory verification. Instead of issuing another verification statement, the ARB verifier must make an attestation to ARB regarding their findings from the desk review. The desk review by an independent body that is accredited by ARB is sufficient to determine if the information originally submitted regarding the offset project is complete and accurate. Therefore, the regulation does not require a site visit unless the ARB accredited verifier cannot find with reasonable assurance that the Offset Project Data Report should have been issued a positive verification statement under the Early Action Offset Program.

The regulatory verification and transition of early action offset credits to the compliance program is a voluntary step. ARB has established rules in the regulation for those who would like to participate in early action offset program. Section 95990(k) of the regulation requires projects developed under CAR's forest protocol version 2.1 to recalculate their baseline based on ARB's Compliance Offset Protocol. This provision is necessary to ensure consistency across all forest projects in the compliance program. Early action offset projects developed under the other protocols mentioned in section 95990(c)(5) must transition to the appropriate Compliance Offset Protocol but do not need to change their baselines.

M-183. (multiple comments)
Comment: There are two challenges with the re-verification requirements in section 95990 (f): (1) How to reconcile any differences found during a re-verification. For example, if the Climate Action Reserve's verification generated 100,000 metric tons, but ARB's verification only yielded 90,000 metric tons, some of the offset credits created by the Reserve would not be valid. Multiple parties now own these credits and some may have been retired; reconciling this difference will be extremely challenging; and (2) Requiring the re-verification of these projects will result in higher costs to the project, which will discourage projects from entering the compliance market and further restrict offset supply. PG&E recommends that either ARB rely on the original verification for

these projects or allow existing offset credits to be used while making the necessary changes to the project for future vintages. (PGE1)

Comment: CERP urges ARB to include regulations clarifying how any recalculation of credits resulting from a re-verification—whether an increase or decrease—will be assessed against the current holders of the credits. It is the Coalition's view that the first step should be to determine what quantity of credits from the project have been voluntarily retired. If the number of voluntarily retired credits exceeds the number of "extra" credits issued, then no action need be taken. The voluntarily retired credits will "cancel out" the excess issuance, and ensure that the AB 32 offset program is whole. If the number of "extra" offset credits exceeds the number of credits voluntarily retired from a project, CERP believes the most equitable and efficient means of addressing the "balance" of extra credits is to apply a recalculation pro rata. For example, if re-verification of a CAR-approved project resulted in a 10 percent decrease in vintage year 2009 CRTs for that project, and zero credits had been voluntarily retired from that project, ARB would allow all holders of vintage year 2009 CRTs from that project to exchange their credits for compliance credits at no greater than a 100:90 ratio. (If, however, 10 percent or more of the credits from the project had been voluntarily retired, no recalculation would be needed). (CERP1)

> **Response:** The commenter's interpretation of how the regulatory verification will be conducted is incorrect. ARB will issue ARB offset credits on a one-to-one basis for each early action offset credit if the ARB accredited verifier determines with reasonable assurance that the original Offset Project Data Report should have been issued a positive verification statement. ARB will not recalculate the number of GHG reductions or GHG removal enhancements achieved by the early action offset project.
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> In addition, we modified section 95990(f) to clarify the requirements for regulatory verification of early action offset projects. New section 95990(f) includes new requirements for regulatory verification that is intended to streamline the process and minimize costs associated with converting the voluntary offsets into compliance offsets that can be used for compliance.

M-184. Comment: CERP urges ARB to adopt a more streamlined approach to early action credit re-verification. At the outset, CERP recommends ARB re-consider whether re-verification of projects is necessary given that all CAR projects have been verified by CAR-accredited verifiers. (CERP1)

> **Response:** We modified section 95990(f) to clarify the requirements for regulatory verification of early action offset projects. New section 95990(f) includes new requirements for regulatory verification that is intended to streamline the process and minimize costs associated with converting the voluntary offsets into compliance offsets that can be used for compliance.

AB 32 requires all offset credits used for compliance purposes to be subject to regulatory verification. ARB cannot rely on a non-regulatory program to perform regulatory verification of offsets that will be used for compliance, and AB 32 requires that all offset credits used for compliance be based on the result of regulatory verification.

M-185. Comment: As currently proposed, the re-verification process is unwieldy; for example, offset credits from a single project's historic vintages are now likely to be owned by many unrelated parties who therefore separately bear the responsibility of reverification. This situation is likely to result in a great deal of duplicate and wasted effort. Similarly, operating projects have ongoing verifier site visits associated with current-vintage verifications. Can these visits, indeed the entire verifications, be combined with current CAR verifications so as to prevent site visits which are duplicative and hence add no value to the regulatory level of assurance? Can a centralized opt-in process for reverification of historic vintages be arranged? How will the timing requirements and restrictions discussed in section 95976 and 95977 be applied to reverifications, and to ongoing CAR and/or regulatory verifications of Early Action projects, if at all? (TPI2)

Response: ARB cannot rely on a non-regulatory program to perform regulatory verification of offsets that will be used for compliance. AB 32 requires that all offset credits used for compliance be based on the result of regulatory verification.

Section 95990(f) was modified to clarify the requirements for regulatory verification of early action offset projects. New section 95990(f)(1) includes new requirements that the verifier performing the regulatory verification services must be different than the one that did the initial verification for the Early Action Offset Program. This ensures that the review is completely independent and unbiased. The new requirements include a desk review of each Offset Project Data Report (new section 95990(f)(3)) by an ARB accredited verification body based on all original early action offset project documentation. This provision was added in response to stakeholder comments to streamline the requirements for regulatory verification. Instead of issuing another verification statement, the ARB verifier must make an attestation to ARB regarding their findings from the desk review. The desk review by an independent body that is accredited by ARB is sufficient to determine if the information originally submitted regarding the offset project is complete and accurate. Therefore, we will not be requiring a site visit unless the ARB accredited verifier cannot find with reasonable assurance that the Offset Project Data Report should have been issued a positive verification statement under the Early Action Offset Program.

M-186. (multiple comments)
Comment: In the event that ARB still considers re-verification necessary, CERP urges ARB to limit the scope of verifier review to confirming that the project complies with ARB requirements and the overall reasonableness of the earlier verification results. The

offset protocols eligible to generate early action credits have built in conservative assumptions and margins of error to account for any uncertainty and variation in the application of a protocol by different verifiers. Unless there is evidence of a material error or misstatement, the regulations should provide that already verified early action credits are presumed to be valid. If evidence of material misstatement is uncovered in the re-verification, then a more intensive review (including requantification and, where helpful, a site visit) would be warranted. Many offset projects, particularly small projects, cannot afford to pay for a second full-scale verification of the emission reductions they generated. In order to ensure that the early action program can appropriately recognize early emission reduction efforts and generate early offset supply, it is very important that the re-verification requirements are rigorous but achievable. (CERP1)

Comment: We recommend that ARB consider a single re-verification process through which early-action projects could be verified as projects under the Compliance Forest Protocol. Valid existing third-party credits from such projects would be exchanged for ARB compliance offset credits and the projects would thereafter be issued ARB offset credits. We strongly support ARB's interest in accurate measurement, reporting and verification (MRV) of offset projects, but in general we feel that the approach outlined in section 95990(f) could be streamlined without sacrificing MRV accuracy or confidence in offset quality. We would suggest that ARB require regulatory verification of projects for early action through a single re-verification of the project, which would transition all eligible credits from that project into ARB compliance offset credits and would enable that project to be registered as a project with ARB and thereafter issued ARB compliance offset credits. This re-verification should not require an additional site visit if a site visit has been performed by an ARB-accredited verification body to the standards of section 95977 within two years prior to said re-verification. The project would be de-listed from the third-party registry and listed with ARB or an ARB-approved registry as a compliance-grade project, approved serialized offset credits would be retired and new ARB compliance offset credits issued in their place, and the project would thereafter be issued ARB compliance offset credits pursuant to the ARB Compliance Forest Protocol. Such a system would maintain high standards for measurement, reporting and verification and a high degree of confidence in offset quality while avoiding the unnecessary multiple site verifications currently required in section 95990(f). (SHILLINGLAW1)

> **Response:** We agree and modified section 95990(f) to include new requirements for regulatory verification that are intended to streamline the process and minimize costs associated with converting the voluntary offsets into compliance offsets that can be used for compliance.
>
> The new requirements include a desk review of each Offset Project Data Report (new section 95990(f)(3)) by an ARB accredited verification body based on all original early action offset project documentation. This provision was added in response to stakeholder comments to streamline the requirements for regulatory verification. Instead of issuing another verification statement, the ARB verifier

must make an attestation to ARB regarding their findings from the desk review. The desk review by an independent body that is accredited by ARB is sufficient to determine if the information originally submitted regarding the offset project is complete and accurate. Therefore, the regulation does not require a site visit unless the ARB accredited verifier cannot find with reasonable assurance that the Offset Project Data Report should have been issued a positive verification statement under the Early Action Offset Program.

M-187. Comment: ARB requires site-based re-verification of CRTs, in addition to CAR verifications, before CRTs can be transferred into the ARB system. Equator strongly urges ARB to consider a more straightforward and less costly approach to early action credit re-verification. Specifically, we suggest limiting the scope of the re-verification review to simply confirm that projects comply with ARB requirements, and that the CAR verification results have been sufficiently robust. (EQUATOR)

Response: The commenter's interpretation of the requirements for regulatory verification is incorrect. ARB will only require a site-visit and full verification services to be performed if an ARB accredited verifier cannot determine with reasonable assurance that the original Offset Project Data Report should have been issued a positive verification statement. In addition, we modified section 95990(f) to include new requirements for regulatory verification that are intended to streamline the process and minimize costs associated with converting the voluntary offsets into compliance offsets that can be used for compliance.

M-188. Comment: Because the CRT registry allows CAR to identify every credit issued to every project, we recommend that ARB-accredited verifiers work directly with the CAR administrators and the project developer in re-verifying eligible CRTs as compliance grade. Early Action Credit owners will in many cases not have access to the requisite documentation to facilitate the re-verification event. In most cases, the project owner/developer is the most appropriate person to coordinate with to achieve re-verification. Since the verifier will already be working with the project developers on the current year verification, they can also provide any documentation for historical issued credits for the purposes of a one-time re-verification. The incremental cost associated with the re-verification of historical issued CRTs can be borne by the current CRT owners. (EVMKTS)

Response: The regulatory verification and transition of early action offset credits to the compliance program is a voluntary step. ARB has established rules in the regulation for those who would like to participate in early action offset program. The Climate Action Reserve and the offset verifiers can work with the project developers and the holders of early action offset credits to transition them to the compliance program, however, ARB will not act as a facilitator of voluntary contracts and voluntary commitments.

M-189. Comment: Establish a "Fast Track" Certification Program for Early Action Credits: Evolution Markets also believes that establishing a clear and efficient certification process for Early Action projects as ARB offsets will incentivize compliance entities to begin using the pre-compliance offsets market to hedge, which in turn helps achieve the lowest cost of compliance. Evolution Markets recommends once ARB-accredited verifiers are available to the market, ARB should allow for re-verification as part of future credit verification events for eligible CAR projects. ARB should consider a special "fast track" procedure for this re-verification, basing documentation for this process on requirements of existing standards. (EVMKTS)

> **Response:** We modified section 95990(f) to clarify the requirements for regulatory verification of early action offset projects. New section 95990(f) includes new requirements for regulatory verification that is intended to streamline the process and minimize costs associated with converting the voluntary offsets into compliance offsets that can be used for compliance. The new requirements include a desk review of each Offset Project Data Report (new section 95990(f)(3)) by an ARB accredited verification body based on all original early action offset project documentation.

M-190. Comment: The Reserve understands the need for the Air Resources Board to require a new verification of all early action credits, as required under AB 32 and described at section 95990. However, these projects have already once undergone verification by a Reserve accredited verifier and a full conflict of interest assessment. Subjecting such projects to another full re-verification is not only costly but unnecessary. To the extent that Reserve accredited verifiers become accredited by the Air Resources Board, we would request that the re-verification process be streamlined and efficient to reduce transaction costs and uncertainty. (CAR1)

> **Response:** ARB cannot rely on a non-regulatory program to perform regulatory verification of offsets that will be used for compliance. AB 32 requires that all offset credits used for compliance be based on the results of regulatory verification.
>
> We modified section 95990(f) to clarify the requirements for regulatory verification of early action offset projects. New section 95990(f) includes new requirements for regulatory verification that is intended to streamline the process and minimize costs associated with converting the voluntary offsets into compliance offsets that can be used for compliance. The new requirements include a desk review of each Offset Project Data Report (new section 95990(f)(3)) by an ARB accredited verification body based on all original early action offset project documentation.

M-191. (multiple comments)
Comment: IETA has concerns the process for accreditation of early action credits and their potential transition to ARB-certified offsets is an administrative burden. In order to bring the greatest level of efficiency to this process, IETA recommends ARB not set a pre-requisite of re-verification of early action offsets and instead define a process in the early stages of the program to enable ARB-approved verifiers the ability to re-verify

Climate Reserve Tonnes (CRT). This will facilitate the process and reduce uncertainty on the transference of CRTs. Such a program will enhance liquidity early in the offsets market, which is essential to reduce compliance costs. This also will enable firms to hedge more confidently early in the program, further reducing the costs of the program. (IETA1)

Comment: The verification process for early action offset credits should be streamlined. There is uncertainty among potential buyers concerning this process to verify existing offset credits. This process could also create a significant cost burden that unnecessarily raises the price of early action offsets. (OFFSETSWG1)

> **Response:** We modified section 95990(f) to clarify the requirements for regulatory verification of early action offset projects. New section 95990(f) includes new requirements for regulatory verification that streamlines the process and minimize costs associated with converting the voluntary offsets into compliance offsets that can be used for compliance.
>
> The new requirements include a desk review of each Offset Project Data Report (new section 95990(f)(3)) by an ARB-accredited verification body, based on all original early action offset project documentation.

M-192. Comment: Section 95990(f) (p. A-174) details the verification process that is required for early action offsets. The ISOR states (at IX-176) that the verification services are provided for the project as a whole rather than separately for each vintage year of credits. However, this is not evident from the regulation, section 95990(f)(3), which refers to verification for each year in which the offsets are issued. The ISOR (at IX-176) also refers to the ability of buyers of early action offsets from a project to group together and obtain one verification rather than separate verifications, but it is not clear how the regulation would accommodate this. In addition, it is unclear what "serialized offset credits" are. This term is used frequently in section 95990(f) but is not defined. The verification procedures in this section would be in addition to the verification that was performed under the relevant CAR protocol when the offset was originally issued. These procedures effectively constitute re-verification of the offsets and will make early action offsets more expensive with little gain. (SCPPA2)

> **Response:** We agree and modified the regulation in section 95990(f) to more clearly state the regulatory verification requirements of Early Action Offset Credits. To streamline the requirements of re-verification, we included provisions to allow all Offset Project Data Reports for an individual offset project to be included in one desk review (new section 95990(f)(3)), in response to stakeholder concerns that regulatory verification costs may be exceedingly high. The term "serialized early offset credits," used in section 95990(f), is a unique number assigned to each early offset credit for identification.

M-193. Comment: Transferring into ARB in 2014 will undoubtedly require certain administrative changes, and submitting to ARB's regulatory enforcement will also be understandably part of acceptance into the ARB system. However, this transfer into the ARB system should not include re-verification under ARB project protocols as this would, in many cases, change project baselines for no practical or beneficial reason. Updating baselines would, in some cases, make projects no longer eligible since certain actions taken (e.g., voluntarily placing a conservation easement on a forest) after the project's original registration could result in drastically different legal constraints in the baseline. As ARB's staff report correctly observes, this type of grandfathering provides a stable regulatory environment that is critical for facilitating investment into offset projects. (EQUATOR)

> **Response:** AB 32 requires all offset credits used for compliance purposes to be subject to regulatory verification. ARB cannot rely on a non-regulatory agency to perform regulatory verification of offsets that will be used for compliance, and AB 32 requires that all offset credits used for compliance be based on regulatory verification. Prior to transitioning to a Compliance Offset Protocol, an early action offset project will be re-verified according to the early action offset protocol that was used at the time the early action offset credits were originally issued by the Early Action Offset Program. Therefore, the commenter's concern about changing the project baseline prior to transition into the compliance program is misguided. That said, in section 95990(k) the regulation requires projects developed under CAR's forest protocol version 2.1 to recalculate their baseline based on ARB's Compliance Offset Protocol. This provision is necessary to ensure consistency across all forest projects in the compliance program.

M-194. Comment: It is unclear in section 95990 and in the conflict of interest provisions (e.g., section 95979(b)(4)) if offset credits registered with a third party offset program can be or cannot be verified by the same verification body that originally verified the project under the third party program. (EOSC1, EOSC2)

> **Response:** Section 95990(f) was modified to clarify the requirements for regulatory verification of early action offset projects. New section 95990(f)(1) includes new requirements that the verifier performing the regulatory verification services must be different than the one that did the initial verification for the Early Action Offset Program. This ensures that the review is completely independent and unbiased.

M-195. Comment: We would recommend not requiring an additional site visit as a part of the regulatory verification if an ARB-accredited verification body has conducted a site visit of that sequestration project to the standards of section 95977 within two years prior to the regulatory verification. Subsequent vintages issued to that project should be issued ARB offset credits following a desk verification of offset data reports. Section 95990(f)(3)(A) requires the verifier to conduct a site visit as per section 95977(e)(2)(C)(iv) in order to verify the offset project and serialized offset credits that will potentially be issued ARB offset credits. Because this section requires the verifier to perform all of the offset verification services in section 95977 "for each offset data report for each year of the offset credits issued by the third-party offset program" (section 95990(f)(3)), the requirement of a site visit would also apply to subsequent vintages as this section is currently drafted. If an early action project seeks verification for 2005-2012 vintages in 2012, and then later seeks to separately re-verify vintages 2013 and 2014 under section 95990(f), an additional two site visits would be required. Thus four site visits could be required in three years for an early action forest carbon project, once to be verified with a third-party registry like CAR in 2011, once to re-verify the project with ARB in 2011 or 2012, and twice in the following two years to verify 2013 and 2014 vintages.

This would seem to require somewhat more site visits than truly necessary for confidence in MRV. New Forests has found that the cost of site visits in forest carbon project verification can be an order of magnitude higher than a desk verification of an offset project data report. Faced with the high cost of multiple site visit verifications, many forest owners would choose to delay re-verification with ARB until they were issued all relevant early-action vintages or delay registration with a third-party registry and look to the full compliance program, in either case delaying the availability and curtailing supply of offset credits.

Because the “facts on the ground” do not ordinarily change materially from year to year, the Climate Action Reserve v3.x protocols struck a sound balance between site visit verification and desk verifications. We would urge ARB to adopt an approach to site verification similar to that taken by CAR. Modify section 95990(f) as follows:

> 95990(f)(e)(A): If the offset project is still in operation, the verification body must conduct a site visit as required in section 95977(e)(2)(C)(iv), <u>unless the offset project has received a site visit by an ARB-accredited verification body to the standards of section 95977 within two years prior to the regulatory verification of offset credits for early action pursuant to this section. Verifications of serialized offset credits issued after the first verification of the offset project under this section shall not require a site visit as required in section 95977(e)(2)(C)(iv) if the project has been verified pursuant to this section within six years prior to the verification of the serialized offset credits in question</u>. (SHILLINGLAW1)

Response: We agree that an additional site visit is not necessary, and we modified the regulation to include a desk review of each Offset Project Data Report (new section 95990(f)(3)) by an ARB-accredited verification body based on all original early action offset project documentation. A desk review by an independent body that is accredited by ARB is sufficient to determine if the information originally submitted regarding the offset project is complete and accurate. We also included provisions to allow all Offset Project Data Reports for an individual offset project to be included in one desk review (new section 95990(f)(3)), to address concerns that regulatory verification costs may be exceedingly high.

M-196. Comment: Section 95977(e) includes a limit of six consecutive years of offset project data verification. This six year limit needs to be adjusted for the first verification on early action projects and for reforestation projects. This is problematic in the first few years due to availability of verifiers and first verification may cover 2007 through 2011 vintages (five consecutive years) thus a verifier will need replacement in one additional year of verification (after only two years of actual work), this is costly and there may be limited numbers of verifiers. Initial or first verification regardless of offset credit vintage years generated should only count as one year towards this verifier year limit. Another drawback to this limit is that a verifier who is familiar with the project and conducts the first site visit (and the entity most likely to recognize issues) is prevented from doing the second required site visit at the six year interval. A more reasonable solution relative to Forest Projects is to have the ARB do random reviews of projects for the purpose of testing the verifiers and thus obviate this verifier replacement requirement. This would be more effective for ARB to assure verifier quality and be much more cost effective for projects, eventually leading to more cost effective offsets to encourage AB 32 implementation. (CAFORESTRYASSOC1)

> **Response:** The commenter's interpretation of the regulation is incorrect. Early action offset credits must be verified according to the requirements in section 95990(f). They do not need to meet the requirements of section 95977(e), now new section 95977.1, as those requirements must be met by offset projects using Compliance Offset Protocols. Once the project transitions to a Compliance Offset Protocol it must meet the requirements of section 95977 through 95977.2. The rotation of verifiers is essential to the independent review of offset project data reports.
>
> Section 95990(f) was modified to clarify the requirements for regulatory verification of early action offset projects. The new requirements include a desk review of each Offset Project Data Report (new section 95990(f)(3)) by an ARB accredited verification body based on all original early action offset project documentation. This provision was added in response to stakeholder comments to streamline the requirements for regulatory verification.

Early Action Conflict of Interest

M-197. Comment: The verifier conflict of interest requirements for early action credits are excessively burdensome, and should be streamlined. The draft regulations contemplate that owners of Climate Reserve Tonnes (CRT) of specific vintages from qualifying projects will be able to exchange those CRTs for offset credits that may be used for compliance in the AB 32 program—subject to re-verification of the project by an ARB-accredited verifier. In many cases, the CRTs from an individual project now are owned by a multitude of buyers. Yet, under the proposed regulations, ARB's verifier conflict-of-interest standards would be assessed against every owner of a credit that could qualify as an early action offset credit under the ARB program. This approach would result in a massively complex and time-consuming conflict of interest assessment process. In addition, it would likely result in the same project being re-verified by multiple verifiers. Not only would this be costly and inefficient, but the verifiers could reach different conclusions about the quantity of offsets earned, which would be difficult to reconcile. These results would defeat the aim of making early offset credits a source of readily available cost containment.

CERP urges ARB to reconsider its approach to verifiers and conflicts of interest in the early action context. One approach would be for ARB itself to appoint a verifier for each early project, which could be supported by charging a small fee for every early action offset credit submitted from that project. Alternately, ARB could apply the conflict-of-interest requirements only against entities that own a substantial portion of credits from an offset project (e.g., 40 percent). An option that would work well for ongoing projects would be for ARB to allow existing, early action-eligible credits to be re-verified during the initial verification process for a project that registers under the ARB protocol, with the conflict-of-interest assessment performed only against the current offset project operator. In any event, it is important to ensure that an early project need only have at most a single re-verification. It would be helpful if the regulations could make clear that a project's qualification for early action credits does not bar the same project from being approved under an ARB protocol, provided that it may not earn two credits for the same ton of emission reductions. (CERP1)

> **Response:** New section 95990(g) was moved from original section 95990(f)(2) and modified so that conflict of interest is now assessed only against any party that holds more than 30 percent of the early action offset credits issued in each data year. Originally the regulation required that conflict of interest be assessed against all holders of the early action offset credits. We made this modification to reflects stakeholder concerns that applying conflict of interest to all early action offset credit holders is unnecessary and overly burdensome.

Early Action Offset Programs

M-198. Comment: Section 95990 (p. A-171) refers to approved third-party offset programs. It is not clear how these programs differ from Offset Project Registries discussed in section 95986 (section 95990(c)) refers to section 95986(d), but this cross-reference does not appear to be correct). Clarify provisions on third party offset programs. (SCPPA2)

Comment: The reference to section 95986(d) in section 95990(c) appears to be a misplaced reference. (SHILLINGLAW1)

> **Response:** We agree and corrected the cross-reference issue. New section 95990(a)(3) (formerly part of section 95990(c)) now includes requirements for Early Action Offset Programs that are similar to requirements identified in section 95986(d) for Offset Project Registries. These requirements are necessary since both types of entities will be fulfilling similar functions within the offsets program, and many of these entities may be acting in both capacities.

Sector-Based Crediting

M-199. (multiple comments)
Comment: Modify section 95991 as follows: Sector-Based Offset Credits. Sector-based offset credits may be generated through reduced or avoided GHG emissions from within, or carbon removed and sequestered from the atmosphere by, a specific sector in a particular jurisdiction. The Board may consider for acceptance compliance instruments issued from sector-based offset crediting programs that meet the requirements set forth in section 95994 and originate from developing countries or from subnational jurisdictions within those developing countries, ~~except as specified in subarticle 13~~. (CCEEB1)

Comment: Section 95991 allows the Board to consider acceptance of compliance instruments issued from sector based offset crediting programs that meet the requirements and originate from developing countries or sub national jurisdictions. However its restriction to "except as specified in sub article 13" seems to imply that the sector based offset credits are geographically limited to US, Canada, and Mexico. We request that you clarify that it is not ARB's intent to geographically limit sector based offset credits to US, Canada, and Mexico. (SHELLENERGY)

> **Response:** We did not make the suggested edit. The interpretation of the language in section 95991 is incorrect. We will only allow sector-based offset credits from other countries in which we do not issue ARB offset credits directly through provisions in subarticle 13. This means that we would not allow sector-based credits to come from U.S., Canada, or Mexico, but could allow them from other developing countries or sub national jurisdictions that are approved pursuant to subarticle 14.

M-200. (multiple comments)
Comment: We would also strongly endorse CARB's consideration of adopting a REDD+ avoided deforestation protocol. California is currently in a unique position in beginning to implement a new cap and trade system which could provide a significant source of demand for pilot REDD+ projects, which are currently excluded both from the EU ETS and the entire Kyoto Protocol framework. REDD projects will not be able to be supported over the long term by the voluntary market, and near-term sources of demand for compliance offsets from REDD+ projects are scarce, recent developments from the COP16 Cancun Agreement on REDD+ notwithstanding. California and Governor Schwarzenegger are to be commended for taking a leadership role in exploring linkages with tropical forest regions in nations such as Indonesia, Brazil, and Mexico for REDD+ projects, and we hope that CARB accelerates its focus on this area for subsequent inclusion in the carbon market here from 2015 onwards. (CLIMATEWEDGE)

Comment: We support a strong role for REDD and urge you to move forward on REDD. (NC7)

Comment: We're very pleased to see the basic architecture for inclusion of sectoral crediting in the rule today, and look forward to further elaboration of those provisions as soon as practicable. A point carbon analysis that was released about a week ago indicates that there will be a shortage of offset supply in California. In the first compliance period that will be about 25 percent. Sectoral crediting and particularly REDD would go a long way to helping with that supply issue as well as being a driver for continued forward action on the global stage, particularly in preventing tropical deforestation but certainly not limited to that. (CCAP2)

Comment: IETA strongly supports ARB's consideration of Reduced Emissions from Deforestation & Degradation (REDD) credits into its state program. (IETA1)

Comment: REDD provisions should be incorporated as soon as possible. Section 95993 of the draft regulation provides placeholder language for potential future crediting of reduced emissions from deforestation and degradation (REDD) projects. It is important to the market and to developing country policymakers to indicate the general criteria and process that will be undertaken to approve REDD activities. It is currently unclear whether CARB will accept only jurisdiction-wide programs or whether it is open to project-based activities. (VCS)

Comment: The VCSA recognizes that the provisions on sectoral crediting are placeholders but we believe the parameters for how sectoral crediting might be incorporated should be outlined a bit more now if at all possible. Given the short duration of the cap and trade program, it will be important to the market and to developing country policymakers to indicate the general process for approving sectoral crediting programs, and the criteria CARB will factor in to do so. We would therefore recommend a criteria- and rules-based approach that would allow any entity meeting such requirements to participate in the program. In addition, the process should be open and transparent. In particular, CARB should indicate the following: Will CARB have an open approach to all geographic jurisdictions and sectors or will it be selective in terms of what countries or sectors can apply; When will CARB start considering sectoral approaches; What are the criteria for acceptance? (VCS)

Comment: We support ARB's decision to allow for the inclusion of a "nested approach" to REDD in section 95994(a)(6) and urge ARB to ensure that sector-specific requirements for REDD include standards and guidelines that also allow for the direct crediting of projects nested within sectoral REDD systems, where appropriate. (NEWFOREST)

Comment: TNC supports the regulatory language suggesting the future inclusion of sub-national credits from reduced emissions from deforestation and degradation (REDD) and proposes explicit language that would also permit crediting of reforestation and improved forest management (REDD+). In addition to the inclusion of deforestation and forest degradation, it is also critical to include forest restoration and improved forest management. We recommend that CARB include explicit language in this section to acknowledge that subnational REDD approaches can also include additional forest activities such as reforestation and improved forest management. However, crediting for these activities should be conditioned on maintaining or decreasing historic emissions from deforestation and degradation. (NC2)

Comment: We support CARB's explicit inclusion of a regulatory pathway to credit reduced emissions from international deforestation and degradation (REDD). Forest loss and degradation are responsible for roughly 12 percent of global anthropogenic emissions, so we are pleased that California recognizes the critical importance of addressing this problem and providing this leadership. We also commend CARB's jurisdictional approach to this issue, as it is important to engage governments to effectively and comprehensively address REDD. In addition to the inclusion of deforestation and forest degradation, it is also critical to include forest restoration and improved forest management. These activities not only remove additional carbon dioxide from the atmosphere through sequestration, they also help reduce deforestation and degradation by ultimately providing restored forested areas that can meet demand for forest products instead of continued depletion of remaining forests. With this in mind, we recommend that CARB include explicit language in this section to acknowledge that subnational REDD approaches can also include additional forest activities such as reforestation and improved forest management. Crediting for these activities, however, should be conditioned on maintaining or decreasing historic emissions from deforestation and degradation. This comprehensive approach to jurisdictional accounting and crediting, or "REDD+", would also be more consistent with CARB's overall approach to forest offset projects from North America, as it includes avoided deforestation, improved forest management and reforestation activities. (NC1)

Comment: PG&E believes that offsets will help California advance the goals of AB 32 while containing the overall cost to the California economy. I'm concerned about the supply of offsets based on my experience with the Climate Smart program. In the first compliance period, estimates are that we will have less than half the necessary volume that will be allowed. Develop infrastructure necessary for offsets from REDD, Reducing Emissions From Deforestation and Forest Degradation. We're encouraged by the MOU that California has with Chiapas and Acre, Brazil, and encourage ARB to develop the working group recommendations outlined in the MOU. They allow ARB to allow REDD offsets within the first compliance period (PGE1, PGE3).

Comment: Develop a pathway for sector-based REDD crediting in time for the first compliance period. We strongly support the inclusion of sector-based credits from Reducing Emissions from Deforestation and Forest Degradation (REDD) in California's cap and trade system. We commend the California Air Resources Board's (ARB) expressed intent in its final draft regulations to link with international REDD programs. ARB's groundbreaking efforts to create a sectoral REDD crediting mechanism will spur action to address a major source of global greenhouse gas emissions and promote significant forest conservation and sustainable development outcomes. Moreover, the rapid and comprehensive development of a REDD crediting pathway is vitally important to ensure adequate offset supply and cost containment of greenhouse gas reductions, especially during the first compliance period. (SHILLINGLAW1)

Comment: COPC believes that REDD credits should be incorporated into the CARB cap and trade system as swiftly as practicable. We are encouraged by CARB's stated goal of including credits from REDD pilot programs at some point during the first compliance period. We encourage CARB to do so, both in order to help ensure an adequate supply of quality offsets, and to send the much-needed signal to California's subnational partners in the developing world. (COPC1)

Comment: I support the REDD program and encourage its speedy development in the first compliance period. ARB is not only developing the first economy-wide cap and trade program in the U.S., but the very first cap and trade program in the world to recognize REDD credit, and we salute the Board for that and look forward to working with you more. (COPC2)

Comment: The rapid and comprehensive development of a REDD crediting pathway is vitally important to ensure adequate offset supply and cost containment of greenhouse gas reductions, especially during the first compliance period. (NEWFOREST)

Comment: DRA is also encouraged by the framework that is established for sector-based offset credits from developing countries, and believes that offset credits from reducing emissions from deforestation and forest degradation (REDD) are important to meet California's demand for offsets. DRA recommends that ARB continues its leading role in developing sector-based offset crediting mechanisms, and work towards approving REDD credits for meeting compliance obligations in the California program. (DRA)

Comment: While necessary approaches, like the nesting of project-level emissions reductions within sub-national programs are being worked out, project developers are keen to know which protocols/methodologies they should invest time in understanding and applying to the design of prospective projects. We would encourage ARB to consider as streamlined a process as possible—while ensuring the highest standards of quality—in reviewing and approving appropriate protocols and methodologies from established voluntary standards and registries like the American Carbon Registry, Climate Action Reserve, and especially the Voluntary Carbon Standard as it is the most widely-used and robust voluntary standard in use around the world. The recognition by California of the Voluntary Carbon Standard for compliance-based purposes would send a clear signal to project developers and governments around the world that the voluntary market has the tools and robustness to be integrated with the regulated market, and we can thus address climate change more quickly and effectively. (SUNONESOLUT)

> **Response:** Thank you for your support and recommendations for incorporating a REDD program into the cap-and-trade program. We believe that a well-designed, strong regulatory framework is critical before any REDD program could be considered and brought before the Board. This would occur after the

Board adopts the cap-and-trade regulation and would require a separate regulation that includes its own public stakeholder review, and a separate regulatory and environmental review process. ARB is awaiting the recommendations from the REDD Offset Working Group to better understand the legal and technical landscape for REDD credits.

M-201. (multiple comments)
Comment: One of the most significant hurdles—if not the most significant one—for the majority of private forest landowners in a country like Brazil is the upfront capital required to design and launch a rigorous project that can then be validated, monitored, and verified effectively. Many such forest-owners are land rich but relatively cash poor, and commercial credit is unavailable for developing projects in what is still considered by lenders as the embryonic and high-risk realm of carbon markets. Landowners also lack the technical expertise required for project development and approval. In a robust, well-designed project, such start-up costs should in theory be readily recouped after the initial verification(s), but that leaves a financing gap for committed, well-intentioned forest-owners to assume such costs at risk. Financial markets and investors in particular can of course help enormously in this regard, but such novel, high-risk investments will need time, a strong regulatory framework underpinning project design and approval, and consistent signals from policymakers to take hold before a forest carbon market can grow to scale. Innovative approaches to providing risk insurance and/or seed money could potentially assist California in encouraging low-cost, high-quality offset credits in significant volumes for compliance buyers that also incentivize private forestland owners who often face significant opportunity costs. (SUNONESOLUT)

Comment: Given the potentially significant role that the private sector could play-whether through financing and/or project development—we would recommend that private-sector actors based in tropical forest countries be represented as actively as possible in relevant forums and consultative processes. As individual companies or as a group, we are happy to participate in such forums and processes and/or recommend potential participants. We believe that the private sector will be the main driver for sustainable forest management- and can play a similarly pivotal role for REDD—with regard to the scale-up necessary to achieve significant results in emission reductions worldwide. In particular—and related to the question of nested REDD above—we believe the private sector should contribute actively to the debates on, and designs of, systems for coordination and REDD accounting, and we would be grateful for opportunities to do so. (SUNONESOLUT)

Comment: IETA believes that the proposed goal of having REDD offset credits from pilot programs enter the California market at some point during the first compliance period is appropriate. Regarding the establishment of reference levels for REDD programs, IETA believes that the staff's initial thinking—that this reference level should be derived from absolute deforestation based on historic emissions averaged over a 10-year period and adjusted if necessary—is a good start, but believes that critical adjustments will need to be made to this historical baseline in many cases.

Regarding the establishment of a crediting baseline, IETA is very concerned about the statement in the Staff Report that the REDD program must set a crediting baseline based on specific targets for 2020 and beyond. Given the tendency to confuse the concepts of baselines and targets/policy goals in recently proposed US legislation, IETA feels the need to emphasize that a baseline sets the incentive to reach a target; the two are not interchangeable.

IETA welcomes the Staff Report's provision for nested crediting for REDD programs under the California cap and trade system. Finding a way to fully integrate project-level activities within a state-wise system is essential to ensure the successful implementation and financing of REDD programs. IETA believes strongly that ARB should consult closely with a wide variety of public and private stakeholders as it moves forward. IETA looks forward to providing further, extensive input to this discussion over the next year. (IETA1)

Comment: I support the possibility of crediting emission reductions from verifiable reductions of tropical forest destruction and degradation. The current placeholder language on sectoral crediting helps establish some of the fundamental principles that will be needed to ensure environmental and social integrity of this program. However, careful decisions on many more details, which staff is now considering, will be necessary before this program can be implemented. (LUDLOW, UCS1, WALTERS)

Comment: I want to commend the Air Resources Board for planning to incorporate sector-based offsets from reduced emissions and deforestation and degradation cap and trade regulation. Deforestation releases as much greenhouse emissions as the global transportation sector, and significantly reducing deforestation emissions is critical to avoid dangerous destabilization. California has the opportunity to lead the world at creating an economic incentive to tropical forests and this can be done with strong social and environmental safeguards. I want to encourage the Board and staff to ensure that sector-based offsets are incorporated into this plan. (SHILLINGLAW2)

Comment: We support the inclusion of social and environmental safeguards in the sectoral REDD requirements. We encourage ARB to rely on existing standards and frameworks, such as those developed by the Climate, Community and Biodiversity Alliance, to implement such requirements. (NEWFOREST)

Comment: We note that the Climate Action Reserve, the Governors' Climate and Forests Taskforce and the Voluntary Carbon Standard have initiated processes to develop sectoral REDD protocols, frameworks and standards. We encourage ARB to participate in these efforts and draw on these processes and the resulting work products in the development of California's sectoral REDD requirements. (NEWFOREST)

Comment: The proposed cap and trade regulation establishes a program to generate offset credits from reduced deforestation and degradation, but does not include language to ensure the rights of indigenous peoples and local communities. California must ensure that the development and implementation of REDD crediting programs do not lead to negative social and environmental consequences. If the rights and participation of indigenous peoples and forest dependent communities are not guaranteed in California's regulation to establish a REDD crediting program, governments are likely to view avoiding adverse social impacts and respecting rights as merely an extra implementation cost, rather than as a contribution to and prerequisite for REDD effectiveness. It is therefore vital to include clear guidance requiring the full protection of the rights of indigenous peoples and local communities. Modify section 95994 to include the following provision:

> <u>Rights of Indigenous Peoples and Local Communities. The program has requirements to ensure that the rights of indigenous peoples and local communities, including their rights to lands, territories and resources, are fully respected</u>. (FRIENDSOFEARTH)

Comment: The inclusion of REDD sector-based offsets is an issue of particular concern. The safeguards listed (III-28) are inadequate, and gloss over a series of fundamental problems with such schemes. These will be exacerbated if the subnational Reducing Emissions from Deforestation and Forest Degradation (REDD) working group of Governors' Climate and Forests Taskforce (GCF) agrees to use REDD credits from states outside the US. (CTW)

Comment: REDD offsets diminish the responsibility to reduce GHG emissions at source, or initiate a path away from fossil fuels in power and industrial sectors. (CTW)

Comment: I object to the forest offset concept as they are generally not based in the Free Prior and Informed Consent (FPIC) of the communities who live in the affected forests. In many countries, benefits from offsets projects will flow to the government, or to the private project developer, instead of to the communities who have managed the land for generations. This leads to inherent violations of FPIC and other human rights safeguards guaranteed through the UN Declaration on the Rights of Indigenous Peoples. It is a sham to say that forest offset programs will protect forest communities and because of that, the Indigenous Environmental Network stands in opposition to these programs. (MASCARENHAS)

Comment: Using a Board approved REDD sector-based crediting programs" is laudable goal as presented in Staff Report: Initial Statement of Reasons (ISOR) but current draft of Draft decision [-/CP.16] "Outcome of the work of the Ad Hoc Working Group on long-term Cooperative Action under the Convention" will not effectively sequester carbon and could further impoverish forest communities and their forests. Nor will REDD achieve numerous criteria set in the ISOR.

Those who have title and benefit from their forests have a stake in their future and are the most likely to protect them. Governments have not protected these forests as effectively as those few forest peoples that have human and tenure rights, and can depend on and defend their forest. Rights we take for granted but now must be extended to forest people. One of the most cost and environmentally effective next steps will be to stipulate that prior to REDD+ funding human rights and resource tenure be enforced statutory rights. (LIPPMAN)

Comment: While we support the idea of a positive offset list, we are concerned that the inclusion of credits from land use and forestry does not adequately address the question of how best to maximize storage of carbon in natural sinks, and, at the same time, diverts resources away from reducing fossil emissions and investing in a low carbon economy. The capacity for carbon sinks to both remove and contribute carbon to and from the atmosphere is considerable. Their introduction into the carbon market as a form of offset risks creating an over-supply of accredited reductions whilst doing nothing to increase the overall demand to cut emissions. And yet it is precisely this that must be urgently increased to answer the risk of global climate change. An additional problem with sinks in the carbon market is the equivalence (or lack of equivalence) between different sources of greenhouse gases. There are two main anthropogenic drivers of climate change—the release of fossilized carbon through the burning of fossil fuels which contributes an additional load of carbon to the atmosphere, and changes made to land and oceans which alter the level of carbon sinks in the biosphere. These two problems inter-relate in complex ways and each needs to be urgently addressed if we are to stabilize our climate within a safe temperature range. By mixing measures to address the reduction in biospheric sinks with measures to reduce the unabated burning of fossil fuels we risk not adequately addressing either problem. A separate mechanism is required to address this and measures to reduce emissions from fossil fuels should remain focused on that issue alone. An optimized program to address changes in biospheric sinks would regulate those companies, such as logging firms, large scale plantation owners and industrialized agricultural firms, to make them responsible for protecting and restoring our land based sinks. We support the development of sectoral offsets where reductions are generated over and above business as usual projections and above basic minimum standards of performance (i.e. benchmarks). Sectoral offsets enable a move away from baseline and credit programs to sectoral cap and trade systems which help to guarantee reduced volumes of emissions and establish a carbon price. (SANDBAGCC)

Comment: I have deep concerns about California's participation in a REDD/carbon offset program. What I witnessed in Cancun was widespread criticism of REDD as a strategy for addressing climate change; indeed, many indigenous peoples' groups and forest-dwelling peoples are concerned that REDD may bring about what they are calling "perhaps the largest landgrab in history." In Cancun, many organizations, were very vocal about their opposition to carbon offset programs in general, and to REDD in particular. Such agreements implicitly promote carbon markets, offsets, unproven technologies, and land grabs—anything but a commitment to real emissions reductions. Language 'noting' rights is exclusively in the context of market mechanisms, while failing to guarantee safeguards for the rights of peoples and communities, women and youth. Using offsets to reduce emissions on paper has multiple negative effects; on the one hand, it fails to actually reduce emissions at the source, which will allow continued toxic exposure of California communities such as those living near the Richmond refineries, Kettleman City, and other hotbeds of polluting industries. On the other hand, offset programs such as REDD use dubious standards and profoundly troubling strategies, such as offering carbon credits to agrofuel/biofuel plantations, waste-to-energy facilities, and other projects that are falsely presented as "green." Indeed, in the state of Chiapas, Mexico, biofuel plantations of Jatropha curcas are extending throughout regions that previously or currently are home to indigenous subsistence farmers. Such plantations—which are erroneously called "forests" under the United Nations definition—involve massive agrochemical inputs, low-wage labor, and displacement of land-based peoples; at the same time, looked at in terms of its entire lifecycle, biofuels have been shown to be just as CO_2 intensive as fossil fuels. In order for California to truly take leadership on the environmental front, we must avoid toxic programs like REDD and carbon offsets in general, which will fail to address the problem of climate change while also leading to human rights abuses and displacement of peoples from their lands in Chiapas and throughout the global South. (GJEP1, GJEP2)

Comment: I ask CARB to incorporate the following recommendations:

1. That a Board approved REDD sector-based crediting programs should require that within the Subnational REDD Program resource rights be made statutory and binding for all indigenous people and other forest peoples whose rights do not conflict with the rights of adjoining indigenous peoples.

2. The Board review a World Bank analysis of the importance of land tenure to REDD+. The World Bank states about, "the role of community-owned forests in carbon sequestration …" That"…the larger the forest area under community ownership the higher the probability for better biodiversity maintenance, community livelihoods and carbon sequestration."

"The growing evidence that communities and households with secure tenure rights protect, maintain and conserve forests is an important consideration for the world's climate if REDD schemes go forward, and even if they do not."

The cost range of recognizing community tenure rights (average $3.31/ha) is several times lower than the yearly costs estimates for an international REDD scheme ($400/ha/year to $20,000/ha/year). A relatively insignificant investment in recognizing tenure rights has the potential to significantly improve the world's carbon sequestration and management capacity. Prioritizing policies and actions aimed at recognizing forest community tenure rights can be a cost-effective step to improve the likelihood that REDD programs meet their goals. World Bank SOCIAL DEVELOPMENT WORKING PAPERS Paper No. 120/December 2009. (LIPPMAN)

Comment: The Indigenous Environmental Network (IEN) has documented severe impacts due to carbon credit trading involving forests, including fake forest protection projects that also cause harm to indigenous people. This is a lose-lose situation for the environment—no reductions in fossil fuel are carried out because the polluter buys credits from the forestry operator. No forests are protected, and human rights are violated. California's Cap and Trade program, which is seeking to expand internationally its linkage to other trading programs, is vulnerable to such bad offsets. (CBE1)

Comment: The current program allows harms to California, for instance, by causing evictions of indigenous people through fake forest offset projects. (CBE1)

> **Response:** Thank you for your concerns and suggestions on the inclusion and design of a potential REDD program. While the regulation provides a framework for the potential acceptance of REDD credits, we do not currently have provisions in the regulation to approve those credits or allow them to be used in the compliance program. We believe that a well-designed strong regulatory framework is critical before any REDD program could be considered and brought before the Board. The REDD Working Group is in the process of developing recommendations, which is anticipated to be presented to ARB sometime in mid- 2012. At that time, we will consider options for moving forward.
>
> We appreciate the relevance each of these tools and suggestions have in developing a REDD program. When it is appropriate for us to begin to consider a REDD regulatory program, we will be analyzing each of these issues very carefully. This would occur after the Board adopts the cap-and-trade regulation and would require a separate regulation that includes its own public stakeholder review and a separate regulatory and environmental review process.

M-202 (multiple comments)
Comment: The draft regulations state that sector-based crediting is a concept that has emerged in international climate forums as an opportunity to broaden the scope and scale of emissions reductions in developing countries. Attempting to transform that concept into tangible programs has proven incredibly challenging to date. We believe that excluding project-based international offset credits from the California cap-and-trade system unnecessarily and quite severely restricts the sectors and countries that could supply offset credits into the California system. We recommend ARB expand the eligibility for international offsets beyond sector-based credits to also include project-based credits issued by external bodies using methodologies approved by ARB. (IETA1)

Comment: ARB's goal is to ensure that offset credits be real, additional, quantifiable, permanent, verifiable, and enforceable, and we will seek to contribute vigorously toward this goal. Project-level activities will be crucial for ensuring a supply of high-quality, reasonably priced REDD-based offset credits, and we would support multiple pathways to compliance standards for nested approaches. By the same token, we would urge that ARB set out a clear timetable for developing and approving the rules regarding sectoral/nested REDD. (SUNONESOLUT)

Comment: We support the early inclusion of forest offsets from Mexico. But we urge ARB to ensure that any such offsets, even if entering through the use of North American ARB Compliance Offset Protocols, fully satisfy ARB's sectoral requirements for international REDD. We believe that all international REDD offsets, regardless of country of origin, should be subject to the same rules and requirements, which will help ensure integrity and asset fungibility. (NEWFOREST)

> **Response:** Thank you for your comments regarding REDD project-based crediting. The Board's direction has been to consider the possibility of linking to programs from developing countries if those program credits are part of a larger regional or subnational program that is achieving region-wide REDD emission reductions. This is to ensure that GHG emission reductions are not isolated at the project level, rather, that the project is one piece of a larger emission-reduction effort by that subnational entity, that the program has a robust monitoring and verification process at the regional/subnational level, and that significant oversight and a regional plan is in place to achieve such reductions. Doing so reduces the potential for leakage, allows for better tracking, and carries out the principle of common but differentiated responsibilities among developed and developing subnational entities.

M-203. (multiple comments)
Comment: CARB has been considering but has not yet adopted a program for REDD-based projects. It is important that CARB proceed to promptly outline a process for developing REDD crediting rules and to commit to a timetable to complete this process in 2011. Further, we would be particularly interested in additional clarity regarding the interaction between this process and the on-going process to define specific linkages with the states of Chiapas in Mexico and Acre in Brazil announced on November 17, 2010, by the Governor's Climate and Forests Task Force. We welcome the opportunity to participate in any working group or public comment process on this matter. (CE2CP)

Comment: California has signed agreements with the States of Acre (Brazil) and Chiapas (Mexico) for the recognition of REDD credits from those regions, but has not stated clearly whether it is open to REDD offsets from other regions in the world. The VCSA strongly recommends that CARB provide additional clarity and detail regarding these provisions at the earliest possible opportunity. (VCS)

Comment: The Climate Action Reserve, the Governors' Climate and Forests Taskforce and the Voluntary Carbon Standard have initiated processes to develop sectoral REDD protocols, frameworks and standards. We encourage ARB to participate in these efforts and draw on these processes and the resulting work products in the development of California's sectoral REDD requirements. (NEWFOREST)

Comment: In executing the recent MOU with the states of Acre and Chiapas, California acknowledged that jurisdictions seeking to supply sectoral REDD offsets to the California carbon market will take varying approaches to integrating local REDD activities within a jurisdictional accounting framework. We encourage ARB to support working group recommendations, as outlined in the MOU, that can meet ARB sector-based REDD offset criteria and can be adopted in time for use in the first compliance period. (NEWFOREST)

Comment: We enthusiastically support the development of a program for REDD and other forestry projects in linked jurisdictions (such as Brazilian states and other partners under Governor Schwarzenegger's Governors' Climate and Forests Task Force), but we are concerned with ARB's apparent rejection of project-based emissions reduction for REDD in favor of a sector-only approach. ISOR at III-22. ARB's conclusions that a sector approach reduces risk of emissions leakage and alleviates competitiveness concerns among trade-exposed sectors, ISOR at III.23, is not sufficiently developed in the proposal and does not support rejection of project-based crediting. Nonetheless, we encourage ARB to act promptly to outline a process for developing REDD crediting rules, with central participation of stakeholders from the private sector, and to commit to a timetable to complete this process in 2011 such that additional forest credits can be available prior to the inception of the market program in 2012. We also ask that ARB provide clarity regarding how ARB's rulemaking process will intersect with the GCF process, including the recent memorandum of understanding signed in November 2010, which we applaud. (BLUESOURCE, FCC)

> **Response:** Thank you for your support and recommendations for incorporating a REDD program into the cap-and-trade program. We believe that a well-designed, strong regulatory framework is critical before any REDD program could be considered and brought before the Board. This would occur after the Board adopts the cap-and-trade regulation and would require a separate regulation that includes its own public stakeholder review and a separate regulatory and environmental review process. On November 17, 2010, there was an announcement related to a Memorandum of Understanding between Mexico, California, and Brazil; the purpose of the MOU was to share information between parties to understand and work through some of the issues that need to be addressed in order for any future program to be developed. A REDD Working Group separate and apart from ARB was established to address technical issues; that group will be presenting its findings to ARB in the mid-2012.

Air Districts Comments Regarding Offsets

M-204. Comment: The draft regulation specifically prohibits local air districts from performing multiple functions related to the cap on Greenhouse Gas Emissions compliance program. However, SCAQMD has staff resources and expertise that can help ensure successful implementation of the program and other stationary source programs under AB 32. The potential conflict of interest issues applicable to for-profit businesses do not exist for a local air quality agency like SCAQMD. Our organization is a sister regulatory agency with public health as the primary motivation. We are not for-profit, and would approach any function with the motivation to do what is right, not to generate income or ensure repeat business. We request the ability to perform multiple functions in the cap and trade program, including holding compliance instruments. For example, we may wish to use offsets to prefund the AQMD Registry under Regulation XVII -Climate Change, which can currently be used for CEQA mitigation. The amount of offsets or compliance instruments that would be held for these purposes would be inconsequential and could not affect market prices or availability of compliance instruments. (SCAQMD1)

Response: The cap-and-trade regulation provides for distinct roles within the compliance offset program. The roles include project developers, offset verifiers, and approved offset project registries. There is a clear separation of roles for offset project developers, verifiers, and registries to keep in place a system of independent checks and balances throughout the whole offset system. This parsing of roles is consistent with international standards and best practices, as well as program elements developed within the Western Climate Initiative, and applies to all participants (private and non-private) that choose to be part of the compliance offset program. It will be important for air districts to decide which role(s) they would like to play in the compliance offset program. Currently, air districts are allowed to develop offset projects using ARB compliance offset protocols, and then have those reductions subject to an independent review by an ARB-accredited verifier.

As with any private entity, air districts that develop offset projects or provide offset verification services cannot also act as an approved registry for the compliance offset program. This separation of roles goes back to the program design, to ensure a system of checks and balances on each step in the compliance offset program.

M-205. (multiple comments)
Comment: CAPCOA would like to have rule language amended to clarify requirements for local air districts regarding what activities could present a conflict of interest for offset verification; and adding language to enable local air districts to be able to provide multiple functions under the program. Local air districts have substantial expertise related to the operations and emissions of stationary sources and can provide technically sound emission and offset verification services. Local air districts do not have a profit motivation, can be an effective regulatory partner with CARB, and also can reduce otherwise needed CARB implementation resources. Add section 95979(g) as follows:

<u>Specific Requirements for Air Quality Management Districts and Air Pollution Control Districts.</u>

(1) <u>If an air district has provided or is providing any services listed in section 95979(b)(2) as part of its regulatory duties, those services do not constitute</u>

non-verification services or a potential for high conflict of interest for purposes of this subarticle;

(2) Before providing offset verification services, an air district must submit a self-evaluation pursuant to 95979(e) to the Offset Project Operator or Authorized Project Designee and CARB or the Offset Project Registry for each offset project for which it will perform offset verification services. The self-evaluation must contain the information specified in section 95979(e) for all entities for which it intends to provide offset verification services;

(3) As part of its conflict of interest self-evaluation submittal under section 95979(e), the air district shall certify that it will prevent conflicts of interest and resolve potential conflict of interest situations pursuant to its policies and mechanisms submitted under section 95132(b)(1)(G);

(4) If an air district hires a subcontractor to provide offset verification services, the air district shall be subject to all of the requirements of section 95979. (CAPCOA1, CAPCOA2, BAAQMD2)

Comment: Similar language to that which CARB staff will be proposing as a 15-day change for the Mandatory Reporting Regulation is requested for the Cap and Trade regulation. The language below would clarify that local air districts would not have high conflicts of interest in performing non-verification services when staff from an air district verifies greenhouse gas offset projects. The rationale for this language is that air districts are regulatory partners, do not have profit motivation, and are not interested in assuring repeat business for verification.

Add section 95979 (g) as follows:

Specific Requirements for Air Quality Management Districts and Air Pollution Control Districts.

(I) If an air district has provided or is providing any services listed in section 95979 (b)(2) as part of its regulatory duties, those services do not constitute non-verification services or a potential for high conf1ict of interest for purposes of this subarticle;

(2) Before providing offset verification services, an air district must submit a self-evaluation pursuant to 95979 (e) to the Offset Project Operator or offset project for which it will perform offset verification services. The self- evaluation must contain the information specified in section 95979 (e) for all entities for which it intends to provide offset verification services;

(3) As part of its conflict of interest self-evaluation submittal under section

95979 (e), the air district shall certify that it will prevent conflicts of interest and resolve potential cont1ict of interest situations pursuant to its policies and mechanisms submitted under section 95132 (b)(1)(G);

(4) If an air district hires a subcontractor to provide offset verification services, the air district shall be subject to all of the requirements of section 95979. (SQAQMD1, SCAQMD2)

> **Response:** We agree with suggested language and added a new section 95979(g) to the regulation that clarifies the conflict-of-interest requirements as they pertain to air districts and air quality management districts.

M-206. (multiple comments)
Comment: We are concerned that there are many restrictions written into the draft regulation that: (a) disqualify local air district participation as verifiers for offsets, and (b) place limitations on the functions that local air districts can provide for the program's benefit. This will lead to inefficiencies in resource allocations, duplication, added cost, and delays to implementation. The main obstacle apparently continues to be a perceived conflict of interest, with which CAPCOA fundamentally does not agree. We believe air districts have demonstrated the fiduciary expertise and responsibility needed to support successful implementation of this program. (CAPCOA1)

Comment: We don't understand why the air districts were lumped together with other for-profit companies that provide verification services in terms of conflict of interest provisions. Air districts and other regulatory agencies in California are subject to conflict of interest safeguards, including ethics training and financial disclosures. We are glad to see that the staff is including mandatory specific provisions for the air district in terms of conflict of interest. We ask that that be clarified also in terms of offset verification. We have some specific language in our comment letter that we think would lead to that end. (BAAQMD)

Comment: The draft regulation specifically prohibits local air districts from performing multiple functions related to the cap on Greenhouse Gas Emissions compliance program. However, SCAQMD has staff resources and expertise that can help ensure successful implementation of the program and other stationary source programs under AB 32. The potential conflict of interest issues applicable to for-profit businesses do not exist for a local air quality agency like SCAQMD. Our organization is a sister regulatory agency with public health as the primary motivation. We are not for-profit, and would approach any function with the motivation to do what is right, not to generate income or ensure repeat business. We request the ability to perform multiple functions in the Cap and Trade program, including commissioning and/or overseeing offset projects. (SCAQMD1)

> **Response:** The cap-and-trade regulation provides for distinct roles within the compliance offset program. The roles include project developers, offset verifiers, and approved offset project registries. There is a clear separation of roles for

offset project developers, verifiers, and registries to keep in place a system of independent checks and balances throughout the whole offset system. This parsing of roles is consistent with international standards and best practices, as well as program elements developed within the Western Climate Initiative, and applies to all participants (private and non-private) that choose to be part of the compliance offset program. It will be important for air districts to decide which role(s) they would like to play in the compliance offset program. Currently, air districts are allowed to develop offset projects using ARB compliance offset protocols and then have those reductions subject to an independent review by an ARB-accredited verifier.

Section 95979 of the regulation was modified to include new Board-directed text in Resolution 10-42 that clarifies the conflict-of-interest requirements as they pertain to air districts.

M-207. (multiple comments)

Comment: Local air districts have the expertise for protocol development and can help ensure high quality offset projects. CAPCOA members are willing to have any offsets developed by local air districts following CARB-approved protocols verified by a third party. This is important to local air districts because they want local co-benefits from offset projects, and to keep investments and jobs local. Local air districts do not have potential conflict of interest issues that private firms may have for implementing projects, verifying reductions or running a Registry. We are not the same as for- profit businesses—our motivation is to do what is right for our local communities and citizens. Having local air districts perform these and other functions will help keep costs down and can reduce otherwise needed CARB implementation resources.

Add section 95989 as follows:

<u>California Air Pollution Control Districts or Air Quality Management Districts.</u>

<u>California air pollution control districts or air quality management districts shall be approved for multiple roles, which include verification of offset projects or emissions data for mandatory reporting, holding compliance instruments, implementing offset projects that are verified by a third party and approved by CARB, and running a Registry; provided the appropriate training, accreditation or approvals are obtained from CARB pursuant to sections 95132, 95978, 95814 and 95986. Decisions on such approval requests shall be provided in a timely fashion.</u> (CAPCOA1, CAOCIA2, BAAQMD2)

Comment: The SCAQMD Board is very interested in potentially running a Registry (electronic bulletin board) for greenhouse gas reductions that could be used for CEQA and compliance with the state's cap and trade program. The motivation is to assist local businesses needing greenhouse gas reductions for CEQA or for the state program. The additional language, below, would enable such participation.

Add section 95989 as follows:

<u>California Air Pollution Control Districts or Air Quality Management Districts.</u>

<u>California air pollution control districts or air quality management districts shall be approved for multiple roles, which include verification of offset projects or emissions data for mandatory reporting, holding compliance instruments, implementing offset projects that are verified by a third party and approved by CARB, and running a Registry; provided the appropriate training, accreditation or approvals are obtained from CARB pursuant to sections 95132, 95978, 95814 and 95986. Decisions on such approval requests shall be provided in a timely fashion.</u> (SCAQMD1, SCAQMD2, SCAQMD3)

> **Response:** Air districts are able to participate in the cap-and-trade program, but must meet the eligibility and conflict-of-interest requirements in the regulation for whichever role(s) they decide to take. The cap-and-trade regulation provides for distinct roles within the compliance offset program. The roles include project developers, offset verifiers, and approved offset project registries. There is a careful separation of roles for offset project developers, verifiers, and registries to keep in place a system of independent checks and balances throughout the whole offset system. This parsing of roles is consistent with international standards and best practices, as well as program elements developed within the Western Climate Initiative, and applies to all participants (private and non-private) that choose to be part of the compliance offset program.
>
> As with any private entity, air districts that develop offset projects or provide offset verification services cannot also act as an approved registry for the compliance offset program. This separation of roles goes back to the program design to ensure a system of checks and balances on each step in the compliance offset program.

M-208. (multiple comments)
Comment: CAPCOA can help fill the need for technically strong offset protocols. CARB staff recently stated that they would not have time to review protocols developed by air districts. CAPCOA recommends that a process be established to bring local air districts, CARB, and other parties together to develop a list of protocols that would be worthwhile to explore developing. If local air districts step up to produce a protocol, they need assurance that timely review and quick approval will be provided once the protocols are technically sound. CAPCOA requests a tangible commitment to air districts. (CAPCOA1, CAPCOA2)

Comment: SCAQMD and other air districts have expertise and resources that can assist CARB in developing additional technically strong offset protocols. We are interested in developing offset protocols that deliver additional greenhouse gas reductions, while also providing local co-benefit pollutant reductions and helping with the economic viability of our businesses and communities. There should be a process to identify needed protocols and a commitment from CARB for substantive and timely review of draft protocols. Add to Resolution as follows:

<u>BE IT FURTHER RESOLVED that the Board directs the Executive Officer to meet with local air districts and other stakeholders in the next three months to identify protocols that will be evaluated for development by air districts. The Executive Officer will provide timely technical review of draft protocols, take the protocols through the public process, and bring multiple protocols to the Board for consideration as soon as practicable.</u> (SCAQMD1, SCAQMD2, SCAQMD3)

> **Response:** We are committed to working with districts to identify new offset protocols that could be included in the cap-and-trade program. As with all protocols and offset project ideas submitted to ARB, we will review and evaluate their potential for use in the program.

M-209. Comment: Local air districts like SCAQMD have the expertise and resources to develop protocols and commission or implement high quality offset projects. Any offsets developed by SCAQMD following CARB-approved protocols will be verified by a 3rd party. Implementing local offset projects retains the investment, jobs, and co-pollutant benefits in the local community. (SCAQMD1)

> **Response:** There is nothing in the regulation to prohibit an air district from becoming and offset project operator that develops offset projects using a Compliance Offset Protocol. Having those projects reviewed by an independent third-party verifier ensures there is an independent review of the offset project data report.
>
> We are committed to working with districts to identify new offset protocols that could be included in the cap-and-trade program. As with all protocols and offset project ideas submitted to ARB, we will review and evaluate their potential for use in the program.

Referencing

M-210. (multiple comments)
Comment: Section 95970(b) should refer to the quantitative usage limit in section 95854. (TPI2)

Comment: Modify section 95970(b) as follows: An offset credit issued by ARB must: (b) when used for compliance under this Article be subject to the quantitative usage limit pursuant to section ~~95855~~ <u>95854</u>. (NCPA1)

> **Response:** We agree and modified the reference in section 95970(b)(3) to reference section 95854.

M-211. Comment: Reconsider the drafting method of how protocols are recognized in the regulation. Listing each approved offset protocol repeatedly throughout the regulation is confusing and suggests that no additional protocols will ever be approved (see, e.g., sections 95973(a)(2)(C); 95975(c), 95976(c) and (d)). Rather than doing this, CARB should consider simply saying, “as applicable in an approved offset protocol,” or “as relevant in the approved offset protocol,” or “as contained in the appropriate protocol.” This will also minimize the regulatory amendments that need to be made each time a new protocol is adopted. (VCS)

> **Response:** In modifying the regulation, we did use the language recommended by the commenter throughout the regulation where appropriate. However, there are some provisions in the regulation where it is necessary to list the Compliance Offset Protocols.

M-212. Comment: The following sections should refer to section 95854, not the more limited section 95995. Modify section 95820(b)(2) as follows: Surrender of offset credits shall be subject to the quantitative usage limit set forth in section 95~~995~~854. Modify section 95821(e) as follows: Compliance instruments specified usage limit set forth in section 95~~995~~854. (TPI2)

> **Response:** This has been addressed in the 15-day changes to the regulation. Thank you for bringing this to our attention.

M-213. Comment: In our review, we observe a couple of occasions in which the citation in the proposed regulation seemed inconsistent with the textual content. IEP recommends review of the following citations to ensure proper referencing.

> i) Appendix A, section 95911(c)(2) p. A-88, it seems the citation in (c)(2) “the auction purchase limit in (A)…” should refer to (1).
> ii) Appendix A, section 95970, p. A-110, it seems the citation in (c)(2) “… subject to the quantitative usage limit pursuant to section 95855” is incorrect. The correct cite is to section 95854. (IEPA)

> **Response**: We corrected the references.

Forest Owner Definition

M-214. (multiple comments)
Comment: Clarify forest owner definition with respect to conservation easement holders. The revised definition of forest owner needs to be clarified with respect to easement holders. The definition asserts that easement holders are not considered a forest owner, but proceeds to define forest owner to include entities that may hold timber rights. However, easement holders may hold timber rights as part of a conservation easement, which creates an inconsistency in the definition. Therefore, the definition does not need to include an explicit exclusion of easement holders. If there are particular sections of the Protocols that should exclude easement holders from obligations of forest owners, those sections should make this explicit. (NC2)

Comment: “Forest owner” should be defined to exclude the fee owner when all timber rights are held in perpetuity by another entity. If one entity holds timber rights in perpetuity on a property and the fee holder has no control over the management of the timber, it would not seem reasonable to define both the fee holder and the timber rights holder as the “forest owner” collectively as currently drafted. Modify section 95802(a)(75) as follows:

> In some cases, one entity may be the owner in fee while another entity may have an interest in the trees or the timber on the property, in which case all entities or individuals with interest in the property are collectively considered the forest owners, unless the owner of the interest in the trees or the timber on the property owns that right in perpetuity and may manage said timber in its sole discretion. (SHILLINGLAW1)

Comment: The definition of “forest owner” in the proposed regulation (section 95802(75)) states that both the holder of timber rights and the landowner are accountable for project reversals. See also Forest Protocol at 6 (stating that “all Forest Owner(s) are ultimately responsible for all forest project commitments”). Land ownership is composed of a “bundle of sticks” and each stick can be separated from the bundle and held by a different person or entity. Accordingly, not all fee title owners of forest land or woodlots will own the timber and/or carbon rights. Since timber rights and carbon rights can be held as a separate property right from fee title to land, the landowner without timber or carbon rights has no legal ability to control forest project activities, and therefore should not be held accountable for forest project commitments associated with timber or carbon rights. This is consistent with ARB’s decision, which we support, to forgo landowner agreements such as the Project Implementation Agreement required under the CAR protocol. However, ARB does not address these issues in its rulemaking materials (see, e.g., ISOR IX-1). Any contractual relationship with ARB should be with the party that owns the carbon and/or timber rights. Similarly, liability for reversals should lie clearly with the holder of the carbon and/or timber rights and not extend to a fee owner without such rights. Accordingly we recommend that the definition of forest owner be amended so that the entity holding carbon rights can be defined as a forest owner where ownership is separated. (BLUESOURCE, FCC)

Comment: The definition of forest owner states that both the holder of timber rights and the landowner are accountable for reversals. Since timber rights are a wholly separate property right from the land, the landowner should not be held accountable for reversal associated with timber rights. A landowner does not have any management control over timber rights, nor does he share in any income associated with the harvest of timber or the sequestration of carbon. We recommend the definition be amended so that a perpetuity timber rights owner with 100 percent of managerial control and ownership of the timber assets can be defined as a “forest owner.” (NISSENBAUM)

> **Response**: We clarified the definition of “Forest Owner” to designate owners of “real” property in the forest as forest owners. In some cases, this could be the

fee holder or timber rights holder. When designating one forest owner for purposes of the offset project operator, the parties may specify in external contracts who has liability for certain parts of the project implementation. We are leaving the specific designation of roles and responsibilities up to the private parties with interests in the forest project, land, or rights. We believe that it is important for the definition of a forest owner to be as broad and inclusive as possible, to capture any entity with an interest in the property involved in the forest project. Aspects of a Forest Project such as soil carbon which is included as a required pool in the case of intensive site preparation, may extend beyond the scope of timber rights. Entities that have ownership of non-timber rights within the project area likely will have some control over activities that may affect forest management or carbon sequestration. Currently, there is no legal framework to specifically address carbon rights, although we are aware that this question is actively being researched. Given all the potential variables and entities that may share ownership or an interest in the property, we believe the most reasonable and comprehensive approach is to have a single forest owner designated as the Offset Project Operator, that will have the primary responsibility for managing the forest project in conformance with the protocol and the regulation, while all forest owner(s) will still share responsibility for all commitments associated with the forest offset project. The forest owner(s) may define in private contracts any specific roles and responsibilities for implementing a forest offset project.

Other Offset-Related Comments

M-215. Comment: These mitigating steps should not be undercut by reliance upon offsets when any other approach is available. Otherwise, the heat and drought and other climate driven stresses threaten to repeat the experience of the Amazon which in the drought of 2005 tipped for one year to not only fail to sequester its usual two to three billion tons of CO_2, but to become a source of carbon nearly as large, with a net loss in planter sequestration as large as the European Union and Japanese emissions combined. US forests are also stressed and the California system must take that into account dynamically in its approach. (SCB)

Response: We agree that a combination of direct measures, complementary policies and offsets are necessary to achieve significant GHG reductions in California and beyond. We believe that reducing GHG emissions from uncapped sectors such as the forest sector is an important part of the state's overall emission reduction goals. We have taken steps to achieve reductions that benefit California; as offsets are limited to eight percent of the total compliance obligation of each entity under the cap and trade regulation. California has been a leader in climate change actions to reduce GHG emissions and the cap-and-trade program is a critical component of California's overall approach. Maintaining carbon in the forest sector domestically and globally is a significant component that must be preserved to address global climate change, and we believe the forest protocol provides for permanence in accordance with AB 32 requirements. The forest protocol includes a host of stringent elements to ensure permanence. These include a 100-year requirement, forest buffer (replacement for involuntary reversals such as fires), invalidation, and replacement requirement for voluntary reversals (meaning those that are caused by purposeful harvesting/ removal), and ultimately, legal enforcement and authority over entities subject to the cap.

M-216. Comment: All credited offset projects should be made available in a searchable, online database. (CACAN1, CACAN2)

Response: Section 95987(b) of the regulation requires Offset Project Registries to make specific information regarding offset projects publicly available. ARB will also make this information publicly available, and is currently in the process of developing an offset information tracking database.

M-217. (multiple comments)
Comment: ARB should develop a clearly defined procedure by which Offset Project Developers and Verification Bodies are able to seek clarification and guidance from staff regarding the implementation of this regulation. (SCS)

Comment: Once guidance documents are developed, EDF recommends CARB actively outreach to interested stakeholders with the guidance documents through open forums and public dialogue to ensure lingering questions are resolved prior to submission of project protocol applications. (EDF1)

Response: Generally, we do not include implementation-related procedures in our regulations. ARB will develop guidance documents as necessary in 2012 regarding specific aspects of the offsets program.

M-218. Comment: We recommend CARB provide additional clarity about the policy toward standardized versus project-based approaches to protocol development. The draft regulation suggests a philosophical preference for standardized protocols (Staff Report, II-45, III-4). However, this preference is not explicitly reflected in the regulation. The VCSA believes it would be helpful to the market for CARB to clearly indicate whether it intends to endorse one approach to protocol development to the exclusion of another, and insofar as CARB has a preference for standardized approaches, it should clarify exactly what this means (i.e., whether standardized approaches relate to the determination of additionality, the calculation of emissions reductions, or both). VCSA encourages CARB to specify that project-based approaches will be accepted for a limited transition period at the beginning of the cap and trade program's implementation, or as a transition to a sector-wide approach. The rationale for this would be threefold: (1) to enable an adequate supply of early offsets for the program; (2) to encourage additional innovation in a still-nascent market, and (3) to recognize pioneers for groundbreaking efforts in protocol development and project investment. Allowing project-based protocols to be approved for a limited time will encourage a diverse and creative range of protocol types over the longer term.

Standardized approaches are limited in number, take time to develop, and require significant resources. The development of project-based approaches can serve to inform the creation of standardized approaches in certain sectors and will provide the necessary incentives to motivate an industry-wide move towards lower carbon emissions. Restricting approved protocols to only standardized approaches could also result in insufficient offset supply arising from a limited set of protocols. (VCS)

> **Response:** We clarified language referring to standardized methods in the regulation; see new section 95972(a)(9) to alleviate confusion in this area. In addition, ARB cannot allow a transition from project-based protocols to standards-based protocols because each protocol must be approved by the Board. Approving additional protocols does not fall under the purview of this rulemaking. If ARB were to adopt any additional protocols that could be recognized for bringing in early action offset credits, it would have to be done as part of a separate rulemaking and approval process.

M-219. Comment: Section 95987(b)(1)(F) requires an offset project registry to publish a project's Commencement Date at the time of the project's listing. We have found that the Commencement Date identified at project Verification can differ from the Commencement Date submitted at listing, in either direction. This usually results from the unearthing of superior documentation of project commencement than was available at listing. There is no conflict or issue with including the date at listing, provided that ARB recognizes that this date may change with the first verification. (TPI2)

> **Response:** ARB is aware that these dates may differ. Additional offset project documentation will provide the actual date if it is indeed different from the original listing date. ARB may choose to update this date, if it is found to be different.

M-220. Comment: Similar to allowances, CARB should identify that offsets have no expiration. This will help keep offset prices consistent with allowance prices and encourage long-term investment in offset projects. Without such clarity, investments in offsets projects will be dramatically curtailed given the slow ramp of the program and concerns around supply of and demand for offsets. (CE2CP)

> **Response:** Section 95922(c) establishes that ARB offset credits do not expire unless retired or surrendered to meet a compliance obligation.

M-221. Comment: Apart from the quantitative limit, it is paramount to ensure that the sector-based offset credits are bankable. This would provide essential efficiency and cost containment benefits as well as potentially strengthen near-term demand for REDD and other sector-based credits in anticipation of greater demand in the future. This is likely the intent of the proposal, but the section on banking (section 95922) says only that allowances from California or other external cap and trade programs are bankable. It also says that other "California compliance instruments" do not expire until surrendered or retired. However, it is important to make sure that the sector-based credits from REDD are defined as "California compliance instruments" since Subarticle

4 on compliance instruments distinguishes between "compliance instruments issued by ARB" and "compliance instruments issued by approved programs." There is no explicit definition of "California compliance instruments." (EDF1)

> **Response:** Although we do not yet include any REDD or sector-based credits in our program, if through a separate rulemaking with an open public process, we were to accept these credits, they would be covered under section 95922(c), which defines the banking rules.

M-222. Comment: For future changes and clarity sake over a 100 year period, ARB should adopt a numbering system for the protocol versions as surely they will be updated and since they would apply for at least one crediting period there will be need to identify which specific protocol applies to a particular project. (CAFORESTRYASSOC1)

> **Response:** Thank you for the comment. We will consider it as we approve and revise Compliance Offset Protocols in the future.

Specific New Protocol Suggestion

M-223. Comment: California Ethanol + Power (CE+P) is in the process of developing a sugarcane and sweet sorghum to energy project in the Imperial Valley. CE+P intends to plant 40,000 acres of sugarcane that will support the facility. The cane will absorb massive quantities of carbon, much of it being stored in the roots of the cane. After 5 years of production, the cane that is in the ground will be turned and left in the ground. During that 5 year period a large amount of carbon would have been captured and stored. CE+P believes that some sort of carbon capture should be calculated and credited and that the benefit of that should fall into the Cap & Trade analysis. In the end, growers of the cane can apply those credits as a way to off-set the cost of planting, growing and harvesting the carbon absorbing crop. It would be the same type of plan we see today, when trees are planted and credit is given or when forests are protected from being chopped down and credit is given. (CEP)

> **Response:** Thank you for the information related to your planned activities. However, we will review any additional ideas for offset projects as part of a future rulemaking.

M-224. Comment: We request the adoption of our GHG offset protocol for Biomass Waste for Energy projects. A copy of the protocol is attached. (PCAPCD)

> **Response:** The energy sector is a capped sector under the cap-and-trade program, therefore it is ineligible to generate offsets. Any use of biomass that meets the reporting and verification requirements of the MRR as listed under section 95852.2 would be exempt from a compliance obligation. Providing offsets credits to those same emissions would result in double-counting under the cap-and-trade program.

M-225. Comment: The most effective way of maintaining stable levels of atmospheric GHG concentrations is to prevent emissions from entering the atmosphere. This can be done in one of two ways: by using less energy and energy-intensive products, or by producing energy and goods in ways that result in lower emissions. Calera's process would enable the use of domestic fossil fuel resources to create energy without the conventionally attendant GHG emissions. Unlike traditional carbon capture and storage (CCS), carbon conversion does not simply store captured CO_2 and transport it to a storage facility. It is instead a means of avoiding CO_2 emissions by converting the gas to a carbonate solid or liquid state, which is no longer a greenhouse gas and will not revert to one. Obviously, emission reductions anywhere on the earth have the same impact in terms of atmospheric concentrations of GHGs. For this reason, Calera urges ARB to revise the proposed Cap and Trade rule to encourage out-of-state sources to reduce emissions through any means, including conversion of greenhouse gases to non-GHG forms. This can be done through enabling such sources to sell offset to covered sources within the State. Calera suggests, therefore, that sources outside the State of California that capture and convert their carbon dioxide gas to non-GHG forms can sell offsets for emission reductions to California sources under the cap. This will provide an incentive for California sources to encourage out-of-state emissions that might be more cost effective but have the same benefits on atmospheric concentrations as in-state reductions. (CALERACORP)

> **Response:** Thank you for the information related to this technology. However, we will review any additional ideas for offset projects as part of a future rulemaking.

Carbon Capture and Sequestration

M-226. (multiple comments)
Comment: The proposed regulation does not allow offset development in the capped sector responsible for significant GHG emissions, and does not provide a mechanism to account properly for emission reductions attributed to CCS. We recommend that CARB develop a compliance grade CCS offset project protocol to promote the use of CCS technologies in both the capped and uncapped sectors. CARB should make available offsets for capped entities to provide additional support to recognize the significant investments required to deploy CCS. (CODEXIS)

Comment: WSPA supports the inclusion of provisions for a carbon capture and sequestration protocol. (WSPA2)

Comment: Request that the program recognize the valuable role carbon capture technologies can play as part of the state's GHG reduction strategy, as well as the way CCS is contributing globally to climate solutions. By providing proper incentives for in-state clean technology development and deployment through policy drivers and strong regulatory signals, California will also promote in-state innovation and green job growth. CARB's Cap and Trade program should encourage carbon capture retrofits to existing fossil fueled generation. As discussed, CCS can greatly reduce the emissions inherent in providing California its baseload generation, and can be applied to significantly reduce emissions from other industrial sources of GHGs. We believe that the final regulation should provide developers of CCS technologies with credit for the significant carbon reductions that may be achieved through the use of carbon capture. We encourage CARB to develop methodology for measuring, reporting, and monetizing these emission reductions to incentivize power plants serving California's electricity load and industrial base to reduce existing emissions through CCS. The development of such a methodology will rapidly promote the research and development required to commercialize this technology. CARB should develop a mechanism to recognize, account for, and verify CCS-related emission reductions. (CODEXIS)

> **Response:** While carbon capture and sequestration (CCS) is a promising technology that may someday prove useful in the effort to avert climate change, it is still a developing technology. California supports research and development of CCS through various efforts, but if a methodology is included in the cap-and-trade program it would be used to reduce the compliance obligation of covered sources, and could therefore not be used as an offset protocol.

N. PROTOCOLS

This section includes comments and responses concerning to the Forest Protocol (Part V of the Staff Report), Livestock Manure (Digester) Protocol (Part IV of the Staff Report), Ozone Depleting Substances Protocol (Part III of the Staff Report), and Urban Forests Protocol (Part II of the Staff Report). Major topics within the Forest Protocol section concern forest harvesting; forest conversion; additionality; permanence; the crediting period; and measurement, monitoring, reporting, and verification. Major topics within the Livestock Manure Protocol section include additionality; the crediting period; and measurement, monitoring, reporting, and verification. Major topics within the Ozone Depleting Substances Protocol Section include additionality; permanence; geographical location of projects; and measurement, monitoring, reporting, and verification.

U.S. Forest Projects

The Air Resources Board (ARB or Board) received extensive comments on the Offset Protocol for U.S. Forest Projects (Forest Offset Protocol or the Protocol). Many of these comments were related to offset credits and forest harvesting, including clear-cut harvesting. In order to most efficiently respond to the broad issue of forest harvesting practices and how it is addressed in the Forest Offset Protocol, we are listing those comments first, followed by a detailed response that focuses on this issue raised in the comments received. Additional comments and responses on the Protocol follow these comments and response.

N-1. (multiple comments)
Comment: Right now, CARB's draft cap and trade regulations risk tolerating an obvious scam. Big polluters like cement plants, electricity generators and oil refineries will simply duck restrictions by buying clearcut offsets. This not only will promote and subsidize the worst kind of forest cutting techniques but also will pose huge questions about CARB's program in respect to additionality, leakage and verifiability. (SIERRACLUBCA1)

Comment: The largest emitters of greenhouse gases (GHG) should always be required to reduce emissions to the fullest extent possible. The option of “buying credits” might be allowed or considered only as a last resort, only after the “emitter” has demonstrated diligent, valid, and long-term efforts to reduce emissions. Otherwise, the activity or operation must be fully curtailed. Bottom line no credits for clearcuts. (PIC)

Comment: Eliminate from the offset program clearcutting of our forests and eliminate the conversion of naturally managed forests into tree clearcut plantations. (GILBERT)

Comment: Don't make clearcutting a part of your climate program. Don't permit clearcutting in the offset regime. This is no way to sequester carbon. Allowing clearcuts as "offsets" will discredit the integrity and credibility of the state's entire climate effort. Do add stipulations that will ensure against changing natural forests into clearcut plantations. (SIERRACLUBCA1)

Comment: I am very concerned that the draft regulations might permit timber management plans that are environmentally damaging and GHG intensive, such as clear-cuts. We are very concerned about the dangers of such practices for watersheds and fish populations. This issue has been publicly discussed for many months, which suggests that the solution is either complicated or politically difficult. In such circumstances, I favor putting the burden of negotiation on the timber companies rather than on the environmentalists. For now, just leave forestry out of the regulations. In a short period of time the industry will come up with an acceptable solution and it can be amended into the rules. At present California has little experience with offsets. It is important for the program to learn to walk before it tries running into difficult areas. If the proposed draft is adopted, the owners of cement kilns, power plants and refineries will have an open season to invest in clearcut offsets which will subsidize highly damaging forest harvest techniques. (BIRDLEBOUGH)

Comment: Please remove clearcutting as an eligible protocol for improved forest management. There are really two reasons for that. One is that the accounting that we have right now for clearcutting is not accurate. It has problems with the base line. It has problems with leakage. It also has problems with the amount of carbon in the soil. A lot of people think that's up to 50 percent. (SIERRACLUB 2)

Comment: I support the concern among my fellow Sierra Club volunteers and others about the regulations allowing forest clear-cut offsets. Please eliminate this provision from the regulations. (CPC2)

Comment: If forest protocols are adopted as currently written, the Board will be endorsing deforestation. SPI and their land management practices are a clear path to a decline in watershed health and many other resource values. Endorsing their destructive practices will not be tolerated, especially coming from a representative public body. (SANDERS)

Comment: Please—this is about a whole lot more than immediate dollar signs. Coming from a logging community, we still recognize the necessity of multiple age forests. There is more to our forests than money. By allowing the clear-cutting and falsehood of the carbon credits to become law, we truly are entering the age of stupid. Our forests can be and should be managed in their total form (i.e. biodiversity) and not just in their profit form. Selling the carbon credits in no way changes the excessive amount of pollution that is expended into our environment. Let's come up with a plan that will be appreciated and praised by the future generations. Thank you for your serious, heartfelt consideration. You have an important decision to make. (ATCHER)

Comment: No clearcutting. (REHG)

Comment: I'm here to remind you that the clearcutting issue in the forest protocol has got to get fixed. (OLIVEIRAM)

Comment: I am writing to urge your board to reconsider and amend the rule to exclude clear cutting from the Carbon Offset Program. (TAYLORS)

Comment: Clear-cutting of forests should not be traded for carbon credits. (TREEFOUNDTN)

Comment: Please add my name to all those concerned with the long term effects of clear cutting. Millions and millions of acres of forest land in California, Oregon and Washington have already been changed to timber harvesting operations. The impacts of these changes will have consequences for the health of us all. Over the years the Board has taken courageous and beneficial action on behalf of the air quality of California. I hope you will be equally conscientious on behalf of our forests' ability to deal with ecosystems, water quality, wildlife habitat, and climate change. (PHELPS)

Comment: Remove clear cutting from the proposed cap and trade program. (DAVISSTEIN)

Comment: The Cap and Trade program would allow "clearcutting" which would destroy our forests and our air and create even more gas emissions than burning fossil fuels. (REED)

Comment: Deforestation is a major contributor to climate change. For the timber industry, Cal Fire, and Air Recourse Board to claim that clearcut logging is good for our climate is an excellent example of Orwelian news speak; clearcut logging equals deforestation. (WILLARD)

Comment: As someone who lives in the Sierra and has been watching the forests be decimated by 20-acre clearcuts and their plantation replacements, I strongly oppose the proposed rules which would not only allow but encourage 40-acre clearcuts and the whole clearcut-plantation system of eliminating mixed forests. Not only does this create incredible ugliness, but much science shows that clearcutting releases so much carbon that it will take up to a century for the new trees to compensate for the carbon released, let alone sequester more. Additionally, the deforestation/plantation model reduces biodiversity among both plants and animals, thus reducing resiliency, which is the key to surviving environmental and climate change. It makes no sense to try to address one environmental problem by exacerbating others. (EPFW2)

Comment: The cap part of this program is a good strategy. Industry should be willingly doing everything possible to stop source pollution, asap. Doing any type of clearcutting of our forests is a bad strategy. Californians and the biodiversity that lives in natural forests need uneven-management, and select cutting. Forests are currently being clearcut even without your cap-and-trade program. Of which itself is controversial. Are you intending to do more clearcutting than the Board of Forestry is already allowing?

See satellite images of what we have lost just in the last 10 years. Please don't let only a market economy dictate how California faces climate change. Please don't ignore the voices and the science of the people, for example; clearcutting forests will not sequester more carbon. Clearcutting more forests will definitely stress even more fragile ecosystems across the state and drive to extinction species of animals and plants that may have not even been identified. You can always take the cap off, you will never be able to put back the natural forests. Please no more clearcutting California's natural forests. (LAWRENCEP)

Comment: The forests support recreation, jobs, and the environment. Allowing clear cutting to be a key component of the cap-and-trade offset will have a detrimental impact to our area. I support timber harvests, both for its contribution to our economy and to maintaining safe communities. Utilizing clear cut harvests as a forest carbon offset, diminishes what we are doing in the realm of land-use, transportation, and housing. I ask ARB to weigh the impact of the Forest Protocol on the local area with the goal you are trying to reach for all of California. (CALLAWAY)

Comment: We urge ARB to eliminate clearcutting of any forests from any offset/sequestration programs and recognize such flimflam as the ruse it is. For "improved forest management practices" to be (mis)used to offset GHG emissions is unacceptable and will result in a shell game that can never be thoroughly monitored. The accounting issues are formidable and, unless curtailed now, will be rendered useless with complicated, multi-layered "schemes." (PIC)

Comment: The idea of cap and trade to help reduce Greenhouse Gas Emissions (GGEs) has some clear benefits if it is within scientifically accepted boundaries that promote less impact to our air quality. However, the current proposal that would allow even-aged management as an offset for GGEs is completely opposite of the intended purpose. In order to reduce our carbon footprint we must embrace forest practices that will be carbon neutral. The only forest practices that are carbon neutral are ones that promote the growth of standing forests by thinning from below and thereby reduce the threat of catastrophic fire. This type of forestry is called sustainable uneven-aged management. Even-aged management or clearcutting is not carbon neutral. It actually increases impacts to our air quality by cutting down forests that should be sequestering carbon while cleaning our air. Please consider carefully any program with market incentives to ensure that the offset is indeed an improvement to our environment. Clearcuts are not, plain and simple. The proposal as written is a mockery of the intended purpose and would increase the problem we are attempting to solve. Please include language that protects our forests in California as they are becoming one of our most valuable assets in dealing with climate change. (MRC)

Comment: I strongly urge the Air Resources Board to adamantly oppose industrial clearcutting of forests as a carbon emission offset. Sustainable harvesting and management is the most prudent means of reducing climate instability and science supports that. We need policy makers who are bold enough to stand up to industry pressure. (CRUTCHER)

Comment: The removal of forest vegetation is not justified by any need to offset carbon emissions. Our forests store carbon. Legalizing the removal of forests to provide carbon emission credits makes no sense. Polluting industries should offset polluting industries. We should not promote forest removal to further encourage polluting industries. (KANGAS)

Comment: Please do not include clearcutting as an offset for polluters. They are destroying the Sierras bio diversity. Supporters' claims of carbon sequestration from clearcutting are in serious question. Two thirds of California's water comes from these mountain watersheds. (SCHANER)

Comment: I strongly urge you to disallow these carbon offsets. Replanting following clearcutting is of questionable value in reducing carbon emissions. Clearcutting is a highly aggressive logging method which reduces biodiversity and the complexity of forest structure; it should not be encouraged in the name of reducing carbon emissions. (KLOSTERMAN)

Comment: Please eliminate from the offset program, the ability of forest companies to clearcut the forests to sequester carbon and add provisions to the offset program which assure that forest projects result in naturally managed, uneven aged forests. (BEILEY)

Comment: Please do not consider clearcutting as an improved forest management practice. Clearcutting at least temporarily destroys the part of the forest that is cut. The cut trees rot, releasing their carbon dioxide. For a while there may be no roots to hold water in the soil; this allows water to run off and erode the land. The eroded soil may reach streams with adverse effects on our drinking water and fish. Clearcut forests have no value for most wildlife or human recreation. (UNGER)

Comment: Inclusion of forest clear-cutting in the cap and trade program makes no sense because it encourages multi-fronted environmental damage with far more potential climate damage than any sequestration gains from resulting lumber products. There is no need to encourage clear cutting with its poorly understood environmental liabilities. This cap and trade program should not encourage smokestack industries to pay for raping our landscape.

- Clear-cutting is a systemically destructive process opening the landscape to erosional damage. The resulting even-aged monoculture tree plantations are more vulnerable to population collapse than forests of diverse age and species.
- Deforestation is the precursor to worsening climate change, (e.g., Easter Island, Middle East, etc.).
- Healthy (uneven aged) forests are natural buffers against desertification, modulating humidity, consuming CO_2, and stabilizing soil carbon (a huge unmeasured reservoir). It takes many decades for a tree plantation to reach the three dimensional carbon density of leaf mass in a mature uneven-aged forest.

- Though lumber companies may claim that sequestration of carbon in lumber products is most efficiently handled by clear cutting, their claims are self-serving. Lumber from judicious mature tree harvesting provides enough off-setting benefit for lumber harvesters. (KRAMER)

Comment: Please do not allow environmental polluters the option of "carbon credits" by clear cutting forests. This completely goes against attempts to green and make clean our environment. (CATTIVA)

Comment: Inclusion of clearcutting as an ARB endorsed sequestration technique completely undermines the value and credibility of the Protocol program and of California's Global Warming Solutions act of 2006. Clearcutting is a flawed and destructive forest management technique, with no potential for timely carbon sequestration. And, as such, it will be a meaningless offset option that will misuse funds that could go to true reductions of emissions through energy efficiency programs and renewable energy development. (CARLONE)

Comment: Forest clearcutting should not be included in the carbon sequestering program of cap and trade. Our forests are vital components in protecting our watersheds, preventing floods, mudslides, sedimentation of our streams, rivers and lakes, helping to replenish our groundwater, and helping to keep our water clear, clean, and healthy for all organisms. (GARCIA)

Comment: Systemic analysis of environmental impacts of greenhouse gases show that if you connect the dots, clearcutting does not have a positive impact on the health of our planet, our state, our lives. Cap and Trade schemes should not allow clearcutting to be considered a sequestration opportunity. Clearcutting with the resultant plantation replantation harms our water supply, our wildlife diversity and is an insult to the integrity of our remaining forests. The science is affected by the interests of for profit timber outfits, just as drug research sponsored by drug manufacturers will more likely be designed to find benefit from the tested drug. (EPFW1)

Comment: No carbon cap and trade credits for clear cutting. Have you even looked at the results of clearcutting? Are you aware of how much carbon is released when you cut down a tree? Are you aware of how much our air quality depends upon trees as filters? Why would the Air Resources Board even waste time considering including the destruction of our forests for cap & trade? (ST)

Comment: The protocols do not fully account for sources of carbon emissions that occur during timber harvesting, when forests are sinks for carbon storage when they are not harvested. In making these determinations, there cannot be any errors or omissions, or the entire purpose and intention of the cap and trade protocols becomes suspect and of course, ineffective at achieving its purpose. (PARKER)

Comment: I ask the Board not to adopt rules that allow timber companies to clearcut our forests and yet sell credits in the process when it takes 80-100 years to recuperate such carbon emissions. (HARD)

Comment: I'm not sure how it makes sense for timber companies to sell carbon credits while at the same time removing carbon-neutralizing/sequestering features from the landscape. Replanting a seedling to replace a mature tree does not defray the carbon sequestration lost, now does it? Not for another three or four human generations will those seedlings that survive (those that survive) be equivalent to those lost. (WALLACE)

Comment: Capping greenhouse gas emissions is a great thing to try to do, but clearcutting forests creates grave problems, like diminished biodiversity, soil erosion, and greater susceptibility to fire and disease. Forests are intrinsic to clean air. It would be unwise to allow clearcutting with the intention of capping greenhouse gasses. (STONEMAN)

Comment: This idea of clearcutting our way out of climate change makes no sense at all. It is not acceptable. I say no to allowing facilities with the greatest emissions such as power plants, refineries, and cement kilns, to avoid reductions by purchasing very highly questionable clearcut offsets, subsidizing the most aggressive and destructive forest harvest techniques. California's working timberlands are important for people, and not just for nature, habitat, and wildlife. Our forests are the lungs of the earth. They purify our air. Please only allow programs that will assure to produce a method that lowers emissions. We must avoid subsidizing clearcutting. It is a huge and unacceptable environmental risk. Please do not let this pass. (LOTUS)

Comment: It's just laughable the logging industry could push through a cap and trade scheme whereby they clear cut, plant a few trees, and get cap and trade revenues from it. (CONNERS)

Comment: Your proposal does not adequately consider all the effects of clearcutting and makes your whole program subject to valid criticism and doubts. California's forests are also important for the ecological services they provide, not only for nature, habitat and wildlife, but for people too. Our forests are the lungs of the earth that purify our air. Our forests control sedimentation and temperature of the waters we drink, and on which our salmon depend for reproduction. Even aged, clearcut forests are less resilient, more prone to fire and disease, and provide less diversity of habitat for the species on which nature and Californians depend. Clearcutting should be outlawed. Your regulations should encourage select harvesting of forests rather than clearcutting. No offsets for clearcutting. (CARLTON, GOGLIA)

Comment: As proposed, the AB 32 cap-and-trade regulation threatens California's forests and the wildlife that rely on them. I am writing to urge you to amend the proposed cap-and-trade rule to exclude offsets from forest management projects that allow forest clearcutting. I implore you not to make forest clearcuts the face of AB 32.

We cannot and should not try to clearcut and burn our way out of climate change (FORMLETTER08).

Comment: Addressing the controversy around clearcutting and the conversion of natural forests to a more simplified condition, it's important to clarify what qualifies as natural forest management. (PFT2)

Comment: Please do not use Clear Cutting as a solution to Climate Change. Improved forest management practices cannot be interpreted as clear cutting. Soil erosion, slash burning, and heavy applications of herbicides which run into nearby streams are practices that were not adequately taken into account when calculations on carbon sequestration analysis was done. Our forests are the lungs and filters for California's diminishing air and water resources. Please do not allow big polluters such as cement kilns, power plants and refineries to avoid their own emissions reductions by purchasing highly questionable clearcut credits. Please protect both our forest and our climate by eliminating clear cutting from the offset program and assuring that natural management of forest projects do not turn into clear cuts. (MINES)

Comment: Including forest clearcutting does greatly increase the possibilities for gaming and for the development of non-additional credits under the forest protocol. If you are going to approve the forest protocol as part of AB 32, do so without the forest clearcutting. (CBD3)

Comment: Including clearcutting in your program calls into question the credibility of the program (particularly for additionality, verifiability, and leakage). It will allow the facilities with greatest emissions (cement kilns, power plants and refineries) to avoid reductions by purchasing highly questionable clearcut offsets, subsidizing the most aggressive and intrusive forest harvest techniques. Even aged, clearcut forests are less resilient, more prone to fire and disease, and provide less diversity of habitat for the species on which nature and Californians depend. We should adopt only programs that will most reliably assure actual sequestration and avoid those that ignore carbon impacts of entire components of the activity seeking to be called an “offset” such as clearcuts. We should particularly avoid subsidizing clearcuts because they are extremely difficult to assure additionality, and they also pose big environmental risks. Please protect the integrity of the climate program and resiliency of California’s forests. By eliminating from the offset program clearcutting of our forests as a way of sequestering carbon, and adding provisions to assure that forest projects do not result in the conversion of naturally managed (uneven aged forests) into clearcut plantations (even aged forests). (FORMLETTER03)

Comment: The protocols for timber management – e.g., “reforestation” and “improved forest management” are nothing more than a wish list for the timber industry, and if implemented as written they will have the net effect of increasing the loss of native forest and the extirpation of the associated plants and animals that comprise California’s native forest biodiversity, while doing nothing to offset or ameliorate global warming and greenhouse gas emissions. Eliminate the credit for business-as-usual, even-aged management (clearcutting) practices in the Improved Forest Management category, and amend Reforestation Project credits to protect native biological diversity. We could go into this in more detail, but suffice it to say that we have voiced our objections to business as usual already. We have tried to explain to you that CDF's CEQA certification of the timber harvest plan process via the Z/Berg-Nejedly Forest Practice Act (the Forest Practice Rules) is not effectively protecting California's forests and conserving the plants and animals which, under the State constitution, belong to all the people of California. In California, under the current rules for timber harvests, California's fabled forest biodiversity is disappearing, acre by acre, year by year. This is entrainment towards extinction. As parties to the development and approval of these forest protocols, the ARB will become a new contributor to the extinction of thousands of plants and animals. I don't think that was your intention. It isn't too late to fix this. (PARKER)

Comment: Clearcuts have no place in the calculation of forestry carbon offsets. Natural forests sequester carbon, but a replanted clearcut site emits more carbon than it sequesters for as much as 20 years. Clearcutting also decreases the ability of forests to withstand climate change. Natural forests also stabilize the soil and reduce flooding, while providing 60 percent of Bay Area water. Clearcutting increases flooding and soil loss and disrupts the water table. Please make sure that clearcutting is excluded from the calculation of forestry carbon offsets. (SREDANOVIC)

Comment: We cannot clearcut our way out of climate change. Please take out provisions that would include clear cuts in the kind of forest projects that are eligible as offsets. (ALLENAMY)

Comment: Please do not allow clearcutting in the cap and trade program. Clearcutting offsets are suspect. We can't allow facilities with huge emissions to avoid their reductions by buying these questionable offsets. Furthermore our working timberlands matter a great deal for purifying our air, for the water we drink. Clearcut forests are more prone to fire and disease, and provide fewer different habitats that various species need, and on which our environment depends. (SEAL)

Comment: We should adopt only programs that will most reliably assure actual sequestration and avoid those that ignore carbon impacts of entire components of the activity seeking to be called an "offset" such as clearcuts. We should particularly avoid subsidizing clearcuts because they are extremely difficult to assure additionality, and they also pose big environmental risks. California's working timberlands are also important for the ecological services they provide, not only for nature, habitat and wildlife, but for people too. Our forests are the lungs of the earth that purify our air. Our forests control sedimentation and temperature of the waters we drink, and on which our salmon depend for reproduction. Even aged, clearcut forests are less resilient, more prone to fire and disease, and provide less diversity of habitat for the species on which nature and Californians depend. (NELSON, ENDICOTT, BITHELL, ENDICOTT, KENNEDYB)

Comment: Please, please, please! Protect our forests, its inhabitants and our planet. Do not pass this very questionable plan to permit market trading of carbon emissions/pollution for forest carbon offsets. This plan permits timber companies to clearcut California's forests, while allowing the companies to sell credits in the process. How long will it take for the forest to grow back to recoup? 80 to 100 years! There is nothing logical about this plan. (MOCIUN)

Comment: My name is Ciyin. I am in the 5th grade and have recently been published in The Gold Edition 2010 Poetry Collection from the American Library of Poetry. I have written you a poem today. When they clearcut they take the trees lives away. That is what I am here to remind you today. When they clearcut, the trees aren't the only thing that gets hurt. The bugs, the animals, and even the dirt, because of the pollution, herbicide pollution. That's no solution. Don't you see? When they cut down the trees, they make it bare. Do you care? Let the forests stand and the land go free, it's a part of you and a part of me. The trees breathe for you and they breathe for me. When your great great grandchildren wonder why and look back on this day. Will they curse you or bless you? It's your decision to say. I live near these sires, where the tall ones fall. /It makes me cry to look at them all. It once was so beautiful and full of life. There's still some left. Please help end this strife. (OLIVEIRA1)

Comment: I am against clearcutting. I don't see any positive things in clearcutting. First of all, all the animals run from their homes in the trees, to the suburbs and cities where they get hit by cars or shot at. Many starve to death. Next, cutting the trees and leaving one or two dead trees is still clearcutting. I go to the areas where they've clearcutted and I never see any natural biodiversity saplings, or any other trees. I don't care if they cut one or ten trees, but when they cut 20 to 30 acres at a time, with nothing left is heartbreaking. I live on 30 acres, do you know how much life is on 30 acres? I don't see why we can't make paper and building products out of hemp. It's a weed! It grows back in a few months. Unlike trees who take a hundred to hundreds of years to grow back. When all these trees are cut the ground water, and animals are poisoned with the big machines they clearcut with. They are also poisoned by the chemicals they spray to make it impossible for anything to grow except their unnatural saplings. Even humans get poisoned because the chemicals go into the air and in our drinking water. Last year, Sierra Pacific sprayed nearly 20,000 pounds of their poison into my country, for clearcuts...FOR CLEARCUTS! Amphibian population is down bird population is down The porcupine is gone! Cancer is on the rise My friends are spilling proteins You should know I used to live in a town that had mills. The loggers used to have work. Clearcutting takes one man, one machine. And it can ruin the forest, and ruin a town. Tell me, what are you leaving for your children? And your children's children. And one day they'll ask you...WHY? (OLIVEIRA2)

Comment: Some friends and I made the following very short youtube video to sing our concern about clear-cutting forests being called a carbon offset. (ROBERTSONR)

Comment: It is difficult to understand how allowing clear cutting can positively influence the carbon content of the atmosphere. What is clear is that the short term effects of harvesting timber add carbon to the atmosphere and clear cutting adds more carbon. The thrust of this proposal is to promote short-term timber harvests increasing the atmospheric carbon load while securing some unknown benefits in a long-term uncertain future. Please remove this provision and rethink the entire protocol. (CARNAHAN)

Comment: I have to say that I continue to be totally bewildered that CARB is even considering the possibility that cutting down trees, even if planting new ones can be considered a method for offset. (BROWNRE)

Comment: It is irrational to allow industries to offset (rather than actually reduce) their carbon emissions by purchasing offsets from a timber harvester who then clearcut the very trees that could help in small measure if they were left standing. The emphasis should be on reducing carbon emissions and only as a last resort offset them. If offsetting is available, the offsets must be truly environmentally beneficial, not destructive. It is imperative that you remove that from your regulations. (VWCSLV)

Comment: CARB needs to clarify that the forest protocol does not permit forest offset projects to generate credits for converting a diverse, natural forest to a simplified even-age stand. (VESSER)

Comment: A looming problem with ARB's proposal is that a large number of carbon offset credits issued throughout the state could come from forest management projects that allow clearcutting. Exclude forest clearcutting from the carbon offset program. (SCCBOS)

Comment: We strongly urge ARB to eliminate from the offset program the clearcutting of our forests as a way of sequestering carbon and to add provisions to assure that forest projects do not result in the conversion of naturally managed (uneven aged forests) into clear-cut plantations. California's working timberlands are also important for the ecological services they provide, not only for nature, habitat and wildlife, but for people too. Our forests are the lungs of the earth that purify our air. Our forests control sedimentation and temperature of the waters we drink, and on which our salmon depend for reproduction. Even-aged, clear-cut forests are less resilient, more prone to fire and disease, and provide less diversity of habitat for the species on which nature depends. Not all offsets are created equal. This is a novel program and the accounting issues are complicated. We should adopt only programs that will most reliably assure actual sequestration and avoid those that ignore carbon impacts of entire components of the activity seeking to be called an "offset" such as clear cuts. We should particularly avoid subsidizing clear cuts because they are extremely difficult to assure additionality, and they also pose big environmental risks. (FFOREVER1, FFOREVER2)

Comment: ARB's proposed Cap and Trade rule currently not only explicitly invites forest clearcutting as a carbon offset project, but also incentivizes the conversion of natural forests into tree farms. This is no solution to climate change, and further threatens forest ecosystems and wildlife already at risk from global warming. The inclusion of forest clearcutting as a carbon offset project undermines the integrity of the program as whole, especially when so many critical flaws remain in the forest offset protocol. ARB's own review of the forest protocol identified fundamental flaws that threaten to undermine the value, additionality, and verifiability of forest offset credits. The Climate Action Reserve, which developed the forest protocol, similarly acknowledged concerns regarding the environmental impacts of forest clearcutting, but has repeatedly and indefinitely postponed any action to address those concerns. When ARB board members raised questions about the inclusion of forest clearcutting when the protocol was first considered in September of 2009, they were assured that these flaws would be addressed and the forest protocol would become the "gold standard" for forest carbon offsets. Unfortunately, the proposed rule fails to address the systemic problems, and more importantly still includes forest clearcutting.

Forest clearcutting and the conversion of native forests to tree plantations pose great risk to the climate, while simultaneously degrading forest ecosystems, water quality, and wildlife habitat, and impairing the forest's resilience to the impacts of climate change. In its current form, the forest protocol lacks credibility because it would subsidize the most intensive and environmentally risky timber operations in order to provide carbon offsets that would allow power plants, oil refineries, and industrial polluters to avoid upgrading their facilities to adopt less polluting technologies. At the same time, the forest protocol fails to account for greenhouse gas emissions associated with logging slash and debris, dead trees, roots and soil, all of which are much greater for forest clearcutting than for native forest management. This is no gold standard.

Not all offsets are created equal. ARB should consider only programs that can reliably assure carbon sequestration and avoid those that introduce additional environmental risks. We cannot clearcut our way out of climate change. Rather than promoting the conversion of native forests to a patchwork of 40 acre clearcuts, California should use this opportunity to incentivize the best kinds and "green" forms of forest management, which can benefit both the climate and the forest. The forest protocol offers many other options that meet these criteria: reforestation projects; preventing the conversion of forests to development; and the conservation of forest resources.

We strongly urge the Air Resources Board to make the following changes: First and foremost, do not include forest clearcutting as part of the California's Cap and Trade offset program. A Forest Project may not include even-aged management. In addition, the forest protocol should not be part of the proposed Cap and Trade rule unless, at the minimum, the following critical amendments are adopted. Forest carbon offset projects may not include conversion of native forests to tree plantations. A Forest Project may not include conversion of native forest stands comprised of multiple ages or mixed native species to even-age or monoculture management, and may not include even-age management of any stand that had been converted to even-age or monoculture management in the harvest cycle preceding the registration of the Forest Project. Forest carbon offset projects must account for changes in down and dead wood and soil carbon pools. Forest Projects that include timber harvesting are required to account for changes in the following forest carbon pools: lying dead wood, and soil carbon.

ARB should consider only programs that can both reliably assure the value of carbon offset projects and protect forest from additional environmental risks. The failure to fully account for the carbon consequences of harvest practices poses risks to the integrity of the entire program and increases the potential for unintended impacts to our forests. We hope we can continue to work with you to address the other flaws in the forest protocol that threaten the conservation of native forests and the wildlife that depend on them. (BATTLECREEK1)

Comment: We support the adoption of the forest protocols, but with regard to concerns raised about the prospect of more diverse natural forests being converted to conditions that are less diverse and more simplified, we recommend that ARB clarify that forest offset projects not do this, and that they do not receive credit if they do this. (NC6)

Comment: By allowing clearcutting, you're allowing big trees to be replaced with this (forest picture of small trees). And this is not going to help us in the next 20 or 30 or maybe more years. (SIERRACLUB3, SIERRACLUB4, SIERRACLUBCA3)

Comment: Please watch Annie Leonard's "The Story of Cap and Trade" to learn how irrational and irresponsible it is to regulate sustainability using credit offsets. This action would let the biggest greenhouse gas polluters (oil refineries, power plants and cement plants) buy offsets in forests throughout the Sierra Nevada and elsewhere, from timber operators that clearcut California's forests. None of the international climate programs include clear cuts, so don't let the timber harvesters set this awful precedent in California's new law. Please take out provisions that would include clear cuts in the kind of forest projects that are eligible as offsets. (CHABAN)

Comment: It would be a huge mistake to include clear-cut type of timber harvest and the resulting even age tree plantation as a way to offset carbon. Once ground disturbance is introduced into the equation then the picture changes dramatically and there is no way to clear-cut without a whole lot of ground disturbance. Where is the science that backs up using plantations generated from clear cuts and includes the huge carbon release from soil disturbance? (ELIAS1, ELIAS2)

Comment: Exclude forest clearcutting from the offset program. Forest clearcutting and the conversion of native forests to tree plantations pose great risk to the climate, while simultaneously degrading forest ecosystems, water quality, and wildlife habitat, and impairing the forest's resilience to the impacts of climate change. Forest projects eligible for offset credit should not include even-aged management, and should not become an incentive for the conversion of native forests to tree plantations. Furthermore, offset projects should account for changes in down and dead wood and soil carbon pools. (SIERRACLUBCA4)

Comment: Three years ago, we urged adoption of those original protocols because in the words of the Chair, investment in this market will lead to forest management projects that will both store carbon and benefit California wildlife and watersheds.

Unfortunately, today, the forest protocols that are embodied in this proposed cap and trade regulation no longer meet that standard because they were substantially amended by the Climate Reserve in 2009. And much of that was done to accommodate the desires of timber companies like Sierra Pacific Industries and trade groups like the California Forestry Association. Those groups, as many recall, opposed the protocol in 2007 because of issues that they were concerned about, largely because they didn't allow clearcutting is one example. Specifically, clearcutting allows native forests to be converted to mono culture tree plantations. The protocols before you today allow this. urging that you not include these forest protocols as part of your regulation unless they are amended to specifically exclude even aged management. Pretty simple and straightforward policy action you can and should take today. And I would urge you not to refer this issue back to the Climate Reserve, ARB staff, or further study, but allow these flawed protocols to move forward intact. These issues were raised at a Board meeting in September 2009, and basically nothing has been done about them by CAR. Instead of fixing the problem, CAR has refused to even calendar for discussion a compromise that many of the groups that will speak next after me had put together. This was a compromise proposed back in January. I think my added concern of referring this back to CAR is it's not a State agency and not bound by the open meeting laws or other transparency requirements that the Air Board and other State and local government agencies are required to follow. In our respects, we think that CAR has bent over backwards. We urge you to not adopt these protocols unless they're amended to remove the clearcutting issue. (SHELLITO)

Comment: I am writing to urge ARB to amend the proposed Cap and Trade rule to exclude forest clearcutting from the carbon offset program, in order to protect forests and the wildlife that rely on them. The proposed Cap and Trade rule not only invites forest clearcutting as a carbon offset project, but also incentivizes the conversion of natural forests into tree farms. Do not include forest clearcutting as part of the California’s cap and trade offset program. (FORMLETTER02, BATTLECREEK2)

Comment: Let's not forget the pictures that I've passed around and shown you that shows the clearcutting damage in our area. And now they're coming back and cutting clearcuts next to clearcuts. All of this is something that California should not want to export to other countries like Mexico or Amazon. We don't need this brand of clearcutting in those countries, too. What we need is clearcutting removed from the protocols. (BATTLECREEK2, FORMLETTER02)

Comment: You need to take the snow pack into consideration. All the science that I have read points to clearcutting as having a devastating effect on the water we all need. (ELIAS1, ELIAS2)

Comment: The Forest Offset Protocol should not include forest clearcutting as an eligible forest project type. The inclusion of forest clearcutting as an eligible management type in carbon offset projects undermines the integrity of the Forest Offset Protocol and the Cap and Trade program as whole. Forest clearcutting and the conversion of native forests to tree plantations increase the risks to forest ecosystems, water quality, and wildlife habitat, and can impair the forest's resilience to the impacts of climate change. The habitat fragmentation caused by forest clearcutting can have a substantial negative impact on forest resilience and climate adaptation. In addition, forest clearcutting and the conversion of natural forests to even-aged plantations can result in tremendous GHG emissions. For example, the conversion to plantations of over 12 million acres of old-growth forests in western Oregon and Washington in the past 100 years has resulted in the release of 1.5 to 1.8 billion metric tons of carbon into the atmosphere. However, the GHG emissions associated with the conversion of natural forests to even-aged plantations would not necessarily be counted under the forest protocol if the project is registered more than 10 years after the conversion occurs. Furthermore, the forest protocol fails to require forest projects to account for changes in the soil carbon and woody debris carbon pools, which can result in substantial GHG emissions due to the impacts of forest clearcutting.

When ARB adopted the Forest Project Protocol, version 3.0, in September 2009, staff assured board members at that time that the issues associated with the inclusion of forest clearcutting would be addressed before the Forest Offset Protocol would be proposed for use in the Cap and Trade program. Since September 2009, the Climate Action Reserve has made some changes to its Forest Project Protocol, but it has failed to address these issues. The Forest Offset Protocol now proposed in the Cap and Trade regulation is nearly identical to the most recent Forest Project Protocol prepared by the Climate Action Reserve, with no substantive changes to the provisions related to forest clearcutting.

The inclusion of forest clearcutting as an eligible project type under the Forest Offset Protocol proposed in the cap and trade rule directly contradicts AB 32's requirement to maximize the environmental benefits from a carbon market program. In order to protect against some of the worst possible unintended consequences and negative environmental impacts, the Forest Offset Protocol should explicitly prohibit forest carbon offset projects that include even-aged management. (CBD1)

Comment: If we encourage clearcutting through AB 32, all the benefits of the forests will be degraded more quickly than is already occurring. Please do not make forest clearcutting count for carbon offsets. (SIERRACLUB1)

Comment: The ARB plan permits timber companies to clearcut California's forests, while allowing the companies to sell "credits" in the process. Since trees take at least 80 to 100 years to recoup their carbon emissions after clearcutting, there is no credible justification for permitting this type of trading. (RIVENES)

Comment: Please protect the public interest by protecting the integrity of the climate program and resiliency of California's forests by eliminating from the offset program clear-cutting of our forests as a way of sequestering carbon, and adding provisions to assure that forest projects do not result in the conversion of naturally managed (uneven aged forests) into clear-cut plantations (even aged forests). (FORESTWATCH,

COMPTON, CASCADEACTION, WREN, BEVINGTON, CHRISR, LEVY, LISH, FORMLETTER10, STEWARTJ, FREDIANI)

Comment: Clarify that the forest protocol does not permit forest offset projects to generate credits for converting a diverse, natural forest to a simplified even-age stand. (KUSTIN04)

> **Response**: Under the ARB Compliance Offset Protocol for U.S. Forest Projects (Forest Offset Protocol), harvesting, including clear-cut harvesting, does not generate offset credits. The protocol requires projects to maintain or increase the standing live carbon stocks in the project area. While harvesting may occur, the protocol accounts for harvesting as a decrease in standing live carbon stocks that must be compensated for by an increase in sequestration in the rest of the forest project lands. Offset credits will not be issued if, over any consecutive 10-year period, the data reports indicate a decrease in the standing live carbon stocks. If such a decrease does occur it may be considered an intentional reversal, requiring the replacement of all credits issued for the reversed carbon.
>
> In addition to the requirement to increase carbon on project lands, projects must be in compliance with all existing rules and regulations to be eligible for generating offsets. The Protocol does not allow any forest management activity that is not already allowed by state, federal, or local laws and regulations. To the extent feasible, the Protocol includes environmental safeguards to help assure the environmental integrity of Forest Offset Projects. These include requirements for projects to demonstrate sustainable long-term harvesting practices, limits on the size and location of even-aged management practices, and requirements for natural forest management, which require all projects to use management practices that promote and maintain native forests comprised of multiple ages and mixed native species at multiple landscape scales.
>
> Concerns about clear-cutting or even-aged management relate to how trees are harvested within a forest, but not directly to the carbon accounting that is at the heart of the protocol. It is possible to harvest more or less biomass than annual growth using even- or uneven-aged management. The protocol does not provide any incentive to harvest more frequently (regardless of method) or to clear-cut an area. Rather, the strongest incentive provided by the protocol is to increase the carbon in standing live trees, and increasing rotation ages (which decreases harvest frequency and intensity) is expected to be one of the most common improved forest management activities.

N-2. Comment: One of the worst parts of the cap and trade rules being considered is the inclusion of clearcutting as an improved "forest management" method under the Forest Project Protocols version 3.2. CAR essentially admits that they do not take into account critical elements of clearcutting methods (soil ripping, herbicide applications, disposal/burning of dead standing and lying wood) which would greatly affect the amount of carbon that is actually sequestered. Clearcutting turns a forest from a carbon

sink into a carbon emitter for at least the next 20 years, precisely the time period where we need to see true reductions in carbon emissions. The protocols also give 100-yr credit for carbon in wood products. Anyone who has replaced a wooden deck, fence or roof knows that these products do no last anywhere near 100 years. They begin decomposing and releasing CO_2 as soon as they are installed. Please protect the integrity of California's forests (the lungs and filters of our air and water), by:
a) eliminating from the offset program clearcutting of our forests as a way of sequestering carbon and by b) adding provisions to assure that forest projects do not result in the conversion of naturally managed (uneven aged forests) into clearcut plantations (even aged forests. (FEICHTL)

> **Response**: Please see our response above regarding forest harvesting and offsets. With regard to harvested wood products, the protocol includes in the accounting boundary the average amount of carbon expected to remain stored in wood products over 100 years. This fraction takes into account that while a large percentage of harvested wood products will have decayed over 100 years, a significant fraction is expected to remain sequestered over the period defined to be permanent. The protocol credits carbon stored in harvested wood products, and also requires that decreases in carbon stored in wood products relative to the baseline be accounted for and deducted.

N-3. (multiple comments)
Comment: Cap and trade is beset with unintended consequences, but the one I object to in this proposal is the inclusion of forest management practices that defeat the purpose of reducing carbon emissions, while increasing erosion, soil & watershed degradation, and poisoning of receiving waters by herbicides and their toxic breakdown products. If forestry is included as offsets, then it should be good forestry that avoids clearcutting or its equivalents, and disallows herbicide use which de-vegetates landscapes, simplifies biologic diversity, and poisons wildlife, including salmonids. (MILLERKEN2)

Comment: Loggers used to have jobs and work. Clearcutting takes one man, one machine, and it can ruin the forest and ruin a town. I don't see any positive things in clearcutting. All the animals run from their homes and the trees to the suburbs and cities. Next, cutting the trees and leaving one or two dead trees is still clearcutting. When all these trees are cut, the ground, water, and animals are poisoned with big machines they clearcut with. They are also poisoned by the chemicals they spray to make it impossible for anything to grow except for their only natural saplings. Even humans get poisoned because the chemicals go into the air and our drinking water. (SOL1, SOL2)

It makes a mockery of the law to allow multi-billion dollar companies to circumvent the laws intended to reduce fossil fuel emissions by paying other multi-billion dollar companies who are already getting tax benefits for TPZ designation to receive double tax benefit for their business activities. It adds insult to injury when those companies utilize clearcutting practices that REDUCE oxygen production AND use herbicides in this process to kill all competing vegetation that then finds its way into the public water supply. Any company that engages in these practices should be automatically deemed ineligible for offset benefits. I would further propose that any company engaging in practices such as these which are clearly not in the public interest be denied TPZ status and have to pay for the damage that they do. It is a sad fact that my County's water district (Calaveras County) cannot even afford the equipment to monitor the herbicides that are leaching into the water supply for not only our County, but for the large urban areas downstream. I think legislators need to adhere to the intent of the law and demand improvement in environmental practices of companies as the law intended. (CALDERWOOD)

> **Response:** Please see our response above regarding forest harvesting and offsets. In regard to herbicide use, the Protocol requires compliance with all federal, state, and local regulations. The Forest Offset Protocol is not expected to have any significant impact on whether forest owners choose to apply herbicides within legal limits as part of forest management activities. To the extent that improved forest management projects increase rotation ages and decrease harvest frequency or intensity, use of herbicides is likely to decrease.

N-4. Comment: Please do not adopt clearcutting as a carbon offset for the Cap and Trade Program. Add provisions to prevent this from happening. Clearcutting destroys the forest and converts diverse habitat into a tree plantation. Logging adds to sedimentation in streams and rivers and is a major source of degradation of fish habitat. Clearcutting is the worst kind of logging. Herbicides are usually applied after clearcuts. Does the carbon offset you are considering take that into consideration? Slash is often burned after a clearcut. Does the carbon offset you are considering take that into consideration? The fungi which knit a forest together are often destroyed during a clearcut. Does the carbon offset you are considering take that into consideration? Please include a provision that would prevent conversion of natural forests into even-aged plantations. (BULGER)

> **Response:** Please see our response above regarding forest harvesting and offsets. As it relates to carbon sequestration, the forest protocol takes into account carbon stored as a result of photosynthesis, which also produces oxygen in the process.
>
> The Forest Offset Protocol does not directly account for impacts of harvest practices on fungi, but rather relies on compliance with relevant laws and regulations, and the natural forest management provisions. Because the protocol provides incentives to harvest less frequently, it is expected that impacts on soils and fungi should be less than the baseline impacts as a result of the project activity.

N-5. Comment: The current draft proposal seems to allow clearcutting as a component of a possible procedure for offsets. This is absurd. Speaking narrowly, the rules should clearly eliminate this possibility and any similar one. More broadly, the rules should clarify require strong verifiability of offsets so that no such possibility could be entertained. (FORMAN)

> **Response:** Please see our response above to forest harvesting and offsets. Verification ensures that all provisions of the protocol and ARB's regulation are followed by an Offset Project Operator or Authorized Project Designee. ARB's regulatory verification program and oversight will ensure that all natural forest management provisions, including limits on even-aged management in section 3.8.4 are adhered to strictly.

N-6. Comment: A program for allowing the clearcutting of trees and then compensating and planting seedlings will not capture global warming gasses and should be eliminated from the Protocol. Clearcutting is destructive to biological systems and alters water resources and characteristics. It is destroying one part of nature to put in balance another part of nature a dichotomy that segments the intended goal of a sustainable world. Allowing an owner to clearcut and then to receive compensation to repair the damage will incentivize the damaging practice. A two ounce tree seedling cannot possibly be equal in sequestering the same amount of CO_2 per year as a mature multi ton giant old specimen. It is a fallacy to expect otherwise and not a real cap and trade offset. The even aged tree stands are more susceptible to forest fires than mixed aged stands of trees putting this protocol at risk of unwittingly adding to greenhouse gases. (STEPHENS)

> **Response:** Please see our response above regarding forest harvesting and offsets. We could not find any definitive evidence as to whether even-age stands are more prone to fire risk than uneven-age stands, and the Forest Offset Protocol requires all forest projects to contribute a percentage of their offset credits to a forest buffer account that will be used to compensate for any unintentional reversals of stored carbon due to fire.

N-7. Comment: The carbon emissions from clearcutting, which includes all the impacts from soil disturbance, are not offset for 80 to 100 years or more. Under this plan, polluters will be able to trade their emissions for credits from forestry "offsets" that are not offsets at all, and will only serve to hasten the demise of the planet and California's rich biological heritage. California's forests are more than chunks of carbon. California's Sierra Nevada and Klamath-Siskiyou forests are designated global biodiversity hotspots. Clearcutting, as practiced by the majority of timber companies in the state and sanctioned by our state regulators, permanently eliminates habitat for entire suites of plants and wipes out the entire home ranges for dozens of animals. Even though trees are replanted, the resulting tree farm bears nothing in common with a natural forest (except for the presence of one or two species of conifers). The net impact of permitting this to continue, and rewarding it under these proposed regulations, will be the certain entrainment of extinction for untold numbers of plants and animals. Loss of habitat will only be exacerbated by the adoption of a program that will not be effective at reducing greenhouse gas emissions. (CHUNG)

> **Response:** Please see our response above regarding forest harvesting and offsets. It is unclear that conversion to a more simplified forest structure would necessarily result in an associated decrease in soil carbon or lying dead wood. Loss of soil carbon is likely to depend on the intensity of the impact to forest soils, and the protocol already requires that soil carbon be included when intensive site preparation activities such as deep ripping, furrowing, or plowing affect greater than 25 percent of the project area during the project life. The protocol also recognizes that lying dead wood is recruited from the standing dead wood pool, and requires both visual inspections of lying dead recruitment by verifiers and minimum standards for standing dead wood recruitment that is increased if a verifier observes that lying dead wood in the project area is not commensurate with recruitment from standing dead trees. We also recognize that lying dead wood provides important environmental and ecological benefits, but that quantification methods for lying dead wood have relatively high uncertainties. For these reasons, we consider the current carbon accounting framework and protocol requirements to be sufficient to prevent or account for significant decreases in the lying dead wood and soil carbon pools.

N-8. Comment: Rewarding deforestation is not even common sense. This needs to be deleted from the legislation. (ESSERMAN)

> **Response:** Nothing in the Forest Offset Protocol or any other part of the cap-and-trade program rewards or incentivizes deforestation—just the opposite is the case, as the protocol includes Avoided Conversion as an eligible project type. An Avoided Conversion Project involves preventing the conversion of forestland to a non-forest land use by dedicating the land to continuous forest cover through a Qualified Conservation Easement or transfer to public ownership, excluding transfer to federal ownership. An Avoided Conversion Project is only eligible if it can fully satisfy the eligibility rules in the Regulation. See section 2.1.3 of the Protocol. Also, please see our response above regarding forest harvesting and offsets.

N-9. (multiple comments)
Comment: CERP requests that ARB modify the proposed regulations so that a forestry offset project may earn offset credits annually based on a remote data review by the verifier, provided that the verifier also undertakes a site visit at least once every six years or more frequently as the verifier deems advisable. (CERP1)

Comment: Calling for a site visit for every forest protocol offset verification report to receive credits is cost prohibitive and unnecessary when you consider the re-inventory of all inventory plots every 12 years. An office review should suffice for annual offset verification with site visits every six years and required new inventory every 12 years. (CFA)

Comment: The requirement calling for a site visit for every forest protocol offset verification to receive credits is cost prohibitive and really unnecessary when you consider the required re-measurement of all inventory plots every 12 years. (CAFORESTRYASSOC1)

Comment: Verification of Forest Offset Credits should occur through field visits at least every six years and annually through examination of inventory data and aerial photographs in all other years. All offsets need to be verified annually. Verification of Forest Offset Projects should allow for office examination of inventory data and aerial photographs in the years in between field visits. Project owners would be responsible for paying back credits if credits were over-estimated during office verifications. ARB would also be responsible for ensuring issuance of additional credits to project owners if credits were underestimated. The change from the CAR v.3.2 protocol made in the draft regulations, which only allow credits to be verified during a field visit, eliminates the cost efficiencies gained by allowing some verifications to occur by office review. If a project owner conducts field verification every sixth year, but can only sell credits after each field verification, five year's worth of credits will be of older than current vintage, and therefore of lower market value. Allowing "office" verifications but requiring true-ups if inaccuracies are found every sixth year reduces the transaction cost burden on the project owner but still creates a reliable system in which error rates on credit approval are likely to be very low. Digital aerial photography can be used very successfully to cross-check inventory data and ensure that forests remain in the age class stated in inventory data. Re-checks of inventory data in the field every sixth year would allow for fine-grain adjustments in the case of minor inaccuracies due to plot-level measurement, but would be no more effective at detecting large-scale deviations from stated carbon stocks than examining photos. (PFT1, PFT2)

> **Response:** In response to this and similar comments, we modified language in the Forest Offset Protocol and cap-and-trade regulation to allow less-intensive (desk review) verification to be conducted in years when a full verification with a site visit is not required. We believe that less-intensive verification as defined in the protocol will be sufficient to provide reasonable assurance, as long as a thorough on-site verification is conducted every six years.

N-10. Comment: Section 2.1.1 of the proposed Forest Project Protocol states that "Reforestation Projects on both private and public lands, excluding federal lands, are eligible" (emphasis added). The Conservation Fund and other non-profit organizations have developed reforestation projects that commence on private lands with the intent of eventual transfer to federal ownership. In the past several years, the Conservation Fund has used donations from individuals and corporations seeking to address climate change to acquire and reforest more than 20,000 acres of private land that had been cleared for agriculture prior to 1990. These properties were subsequently transferred to the U.S. Fish and Wildlife Service for long term stewardship and monitoring. Many more tens of thousands of acres could be similarly acquired, reforested and managed if they were eligible to provide offset credits under the ARB Forest Project Protocol. We therefore recommend that projects that commence on private land for the eventual transfer to federal ownership be allowed under ARB's Forest Offset Protocol. (TCF)

Comment: Clarify the status of private projects transferred to federal ownership under ARB's Forest Project Protocol. Section 2.1.1 of the proposed Forest Project Protocol states that "Reforestation Projects on both private and public lands, excluding federal lands, are eligible" (emphasis added). The Conservation Fund and other non-profit organizations have developed reforestation projects that commence on private lands with the intent of eventual transfer to federal ownership. In the past several years, the Conservation Fund has used donations from individuals and corporations seeking to address climate change to acquire and reforest more than 20,000 acres of private land that had been cleared for agriculture prior to 1990. These properties were subsequently transferred to the U.S. Fish and Wildlife Service for long term stewardship and monitoring. Many more tens of thousands of acres could be similarly acquired, reforested and managed if they were eligible to provide offset credits under the ARB Forest Project Protocol. We therefore recommend that projects that commence on private land for the eventual transfer to federal ownership be allowed under ARB's Forest. (USFWS)

Comment: CAL FIRE supports the addition of public land project eligibility, however we suggest adding language that clearly allows for future consideration of forest offset projects on federal lands. The US Forest Service owns about 12 million acres, or over half of the conifer forest and woodlands in California. Approximately 261,000 acres burned into a deforested condition between 2000 and 2009. While about 125,000 acres have been planted, funding to restore these lands to forests has not kept pace with the level of level of disturbance, generating a backlog of reforestation needs that are not currently being met. CAL FIRE appreciates the policy and legal complexities of developing carbon offset projects and binding agreements with the State on federal lands. We also understand that the US Forest Service is evaluating their policies in this regard. However, we suggest ARB include a specific placeholder, similar to the language in Version 3.0 that says, "Forest projects on federal lands may be eligible if and when their eligibility is approved through a federal legislative or regulatory/rulemaking process." (DFFP2)

Comment: We are pleased that the proposed regulations recognize the large potential for emission reductions and removals on federal lands, and we appreciate your careful consideration of the legal and regulatory implications of these standards. But we believe our agency's successful record of carrying out carbon offset projects combined with the huge potential to continue to build on these beneficial programs across the more than 150 million acre National Wildlife Refuge system are strong arguments for including these lands in this emerging offset program. We further encourage the Board to consider the unique management practices and mandates of the U.S. Fish and Wildlife Service, as it may not be necessary to enact the same protocols across all federal lands. (USFWS)

> **Response:** Projects on federal lands present an added level of complexity that requires further study before ARB may be able to accept such projects. These complexities include questions related to jurisdiction and enforcement authority, ownership of offset credits, and project approval processes. We recognize the

large potential for emission reductions and removals on federal forest lands, but believe that offset projects on federal lands necessitate further review and potential revisions to the protocol at a later point. It is not the intention of ARB to discourage carbon sequestration activities on federal lands. We are open to the possibility of reconsidering the eligibility of projects on federal lands if the policy and regulatory issues can be resolved.

N-11. Comment: The forestry protocol states in section 3.3 that “projects must be listed within six months of the offset project commencement date.” This seems to present a barrier for projects with a 2007-2010 commencement date, based on the triggers listed in section 3.2. Is this intended as such? Does the protocol assume that the project would have been listed with CAR and that the CAR listing satisfies this requirement? It seems like an unnecessary barrier to certain projects. (CIG)

> **Response:** We agree that there may be a number of legitimate reasons why a forest project would not be able to be listed with ARB within six months of the commencement date and removed this sentence from the Forest Offset Protocol.

N-12. Comment: The forestry protocol states in section 3.5 that conservation easements must “expressly acknowledge that ARB is a third party beneficiary of the conservation easement with the right to enforce all obligations under the easement.” Again, this is a barrier for projects with a 2007-2010 commencement date, for which the relevant easement would already be in place. It seems to us that a Federal conservation easement that, for example, protects project lands in perpetuity and subordinates all timber harvest rights under the easement, which is itself legally enforceable under state and Federal law, ought to provide a sufficient basis for enforcement. (CIG)

> **Response:** Under the Forest Offset Protocol, only avoided conversion projects require a Qualified Conservation Easement to be eligible; other project types may reduce their risk rating and required forest buffer account contributions with a Qualified Conservation Easement but would still be eligible if the easement was not “Qualified.” Offset Project Developers or Authorized Project Designees may be able to modify an existing easement to include ARB as a third-party beneficiary so that it will meet the definition of a Qualified Conservation Easement. Requiring ARB to be a third-party beneficiary to a conservation easement ensures that the provisions of the easement are enforceable and that ARB would be a party to any potential future modifications to the easement.

N-13. Comment: Approval for Harvest in Reforestation Projects to Reduce Disease Threat: Section 2.1.1 of the Forest Protocol requires that trees can only be harvested within the first 30 years of a reforestation project if it is needed to prevent or reduce an imminent threat of disease. Such harvesting could only occur if "the government agency in charge of forestry regulation in the state where the project is located stipulating that the harvesting is necessary to prevent or mitigate disease on reversals." It is not clear that existing CAL FIRE permitting actions will meet ARB needs and the intention of this section of the Forest Project protocol, nor that the Board of Forestry has the authority to address this issue. CAL FIRE suggests that ARB consult with CAL FIRE and the Board of Forestry to discuss the adequacy of existing permitting activities, and, if needed, alternatives such as non-regulatory CAL FIRE assistance to operators and the Cap and Trade Program or additional BOF authority for other measures. (DFFP1)

> **Response:** This approval for harvest referred to in section 2.1.1 does not need to involve a permitting action but rather a "written statement" from the government agency in charge of forest management activities in a state where forest management activities may be undertaken. If a government agency does not provide written support that the planned harvest is needed to prevent or reduce an imminent threat of disease, then such harvest either could not occur or would render the project ineligible according to the requirements of section 2. We thank CAL FIRE for their willingness to coordinate and work with us, and we welcome discussions with CAL FIRE staff about forest protocol requirements.

N-14. Comment: The summary of the Risk Analysis still refers to the Project Implementation Agreement, which will no longer be required. Under Section 9.1 the word "is" in the second paragraph needs to be struck. In Section 3.2 in the second full paragraph, there is a double period typo. (CAFORESTRYASSOC1)

> **Response:** These issues were corrected in the Forest Protocol.

N-15. Comment: Under Section 9.1.1.1 of the Forest Protocol, item #27 requires reporting of projections of baseline and actual harvests from the project area over 100 years. The Board of Forestry and CalFire recognize that such actual harvest projections need to be treated as confidential trade secret information as such estimates can impact a forest owner's competitiveness. An alternative would be to mark such data as 'confidential' according to Section 96021 of the regulation. This can be fixed by moving this item from this list since it is already required in the Annual Offset Project Report, at which time it will also be real and known from actual measured harvest. (CAFORESTRYASSOC1)

> **Response:** We understand the commenter's concern about keeping confidential business information private, and have incorporated the suggested changes by requiring this information to be submitted with the offset project data reports, but not with the project listing information.

N-16. Comment: Item 20 from that list (Project Listing Information) also needs hectare to be replaced by acre, for US based projects. (CAFORESTRYASSOC1)

> **Response:** We agree, and for consistency replaced all references to hectare units in the protocol with acre units, which are more commonly used than hectares in U.S. projects. We believe that this will minimize calculation errors

due to unit confusion and will avoid an unnecessary unit conversion calculation for many forest owners.

N-17. Comment: Section 3.8.3 of the Forest Project Protocol requires live carbon stock must be maintained and/or increased during project life. This provision needs to be revised to state that this is required for the crediting period and that after such period standing live carbon stocks may increase or decrease as long as it does not fall below that level to support all registered tonnes. This could easily be clarified by adding a fifth exception to Section 3.8.3. (CAFORESTRYASSOC1)

Response: We agree with the commenter that such an exception is permissible and does not affect the permanence of credited reductions. We added an exception to section 3.8.3 that the standing live carbon stocks may decrease as long as the decrease occurs after the final crediting period (during the required 100-year monitoring period) and the residual live carbon stocks are maintained at a level that assures all credited standing live carbon stocks are permanently maintained.

N-18. Comment: The annual reporting and six year site visits as well as the full inventory every 12 years should only be required for the crediting period, and that ARB develop monitoring period requirements that recognize the 100 year permanent and the need being of lower resolution, and an investment and detail level that demonstrate that the level of onsite carbon stocks must be maintained at or above that amount needed to assure all registered tonnes (for example, a satellite monitoring of change detection) (CAFORESTRYASSOC1)

Response: We understand the desire for less-intensive monitoring following the end of a final crediting period; however, we did not modify the monitoring and verification requirements. Verification is only required once every six years, and we are confident that this provides a sufficient level of rigor to ensure that credited reductions are being permanently maintained. We have not explored other monitoring options in sufficient detail to have confidence that they could adequately ensure that all credited reductions are being maintained with reasonable assurance.

N-19. Comment: In Section 6.1.1 Estimating Baseline Onsite Carbon Stocks there is a requirement for a pre-site prep inventory for pools that may be affected by the site prep. While very few pools would be affected by site prep, for early action projects this pre-site prep inventory cannot be measured. Suggest adding a professional estimate by an RPF based upon non-reforested areas nearby and including a specific requirement for verifiers to check this estimate for reasonableness. (CAFORESTRYASSOC1)

Response: The ARB Forest Offset Protocol requires that an inventory must be conducted prior to any site preparation activities for carbon pools affected by site-preparation activities, and is contained in versions 3.0 through 3.2 of the CAR protocol, though the requirements are more detailed in version 3.2 and the ARB protocol. We are not aware of any early action reforestation projects under version 2.1 of the CAR protocol. Consequently, we do not see any barriers to transition for early action reforestation projects that followed the requirements in versions 3.0 through 3.2 of the CAR Forest Project Protocol and conducted inventories of carbon stocks prior to site preparation activities.

N-20. Comment: Since the ARB Forest Offset Protocol Resources website is not yet available, it was impossible to check some of the required values for species composition and common practice values, which will require further comment when they become available. (CAFORESTRYASSOC1)

Response: The ARB protocol had citations or links to materials referenced within the protocol. In addition, supporting files and data that will be included on ARB's website at a later date were available for public review at ARB's offices at the Cal/EPA building in Sacramento during the 45-day comment period.

N-21. Comment: Section 6.2.6 for quantifying secondary effects of projects that reduce harvesting fails to account for differences in timing of baseline estimates and actual project real harvesting. The calculation is done annually and does not take into account timing of harvest and would require secondary effects contributions from projects that over time increase harvest above average baseline carbon harvests and thus have no reduced harvesting secondary effects. This methodology also applies a 20 percent multiplier to total onsite carbon harvested when the leakage effect is only applicable to the harvested wood products, since all other pools are required to be stable or increasing this overestimates the leakage effect. The required onsite carbon stock maintenance or increase takes care of the carbon in the non product portions of harvested trees at issue. An identical overestimate occurs in the contribution to landfills for those projects that harvest more than baseline. See Appendix C in Section C.4 - this calculation requires landfill deductions even though the project increases wood product production as compared to the baseline. In both cases, the verifier could evaluate the project and determine if it will actually harvest more than the baseline over the crediting period and correctly calculate these contributions. This decision can be re-evaluated at each six year site visit and if needed corrected in the inventory true up process. (CAFORESTRYASSOC1)

Response: We understand the commenter's concern about the quantification of secondary effects (emissions leakage) due to decreased harvest; however, the forest offset protocol adopted by ARB addresses this concern already with a change that was initially incorporated into version 3.2 of the Climate Action Reserve forest project protocol and subsequently into ARB's protocol. In section 6.2.6, when secondary effects due to harvest are evaluated, the differences between actual and baseline harvest for the current and all previous years are summed. If the result is that actual harvest has exceeded baseline harvest over the life of the project, then the discount is not applied in the current reporting year. However, if the baseline harvest has exceeded actual harvest, then the deduction is applied in the current reporting year. The equation that addresses carbon in harvested wood products entering landfills functions in the same manner, by evaluating the summed difference between actual and baseline carbon entering landfills over the project life before determining if the deduction will be applied in the current reporting year.

The application of the secondary effects deduction for reduced harvest to total onsite carbon harvested (rather than only the carbon entering wood products) is appropriate because the full effects of emissions leakage involves all the carbon in the harvested trees, and not just the wood products. The deduction for the secondary effects is only applied once, and we do not agree that the onsite carbon stock maintenance requirements account for the non-product portion of the emissions leakage.

N-22. Comment: ARB has eliminated the requirement for a deed restriction and the project implementation agreement from CAR's version 3.2. Permanence is still 100 years past your last offset sold. Some of the buffer pool risk rating values will need to be adjusted now that a "Qualified Deed Restriction" has been removed; the default financial risk is now five percent for all offset credits issued, which is way too high. There is no evidence of a five percent rate of financial failure for forest owners. The work group assumed that most projects would also include a deed restriction as well, and receive the one percent default financial risk, which is a much more realistic value. Small non-capitalized projects may have slightly elevated risk, but still less than two percent. We would recommend that ARB correct the table replacing five percent with two percent and allow verifiers to consider forest owner capitalization and allow reduction even without a Qualified Conservation Easement to one percent. (CAFORESTRYASSOC1)

Response: At this time, we do not recognize a deed restriction as achieving the same level of risk mitigation as a Qualified Conservation Easement, which must explicitly list ARB as a third party beneficiary of the conservation easement with the right to enforce all obligations under the easement and all other rights and remedies conveyed to the holder of the easement. At the outset of the cap-and-trade program, there is not sufficient data to determine if all the initial risk values used in determining the forest buffer account contribution have been calculated appropriately. However, in the absence of better risk data and based on the principle of conservative accounting, we believe that it is important to err on the side of having the risk factors too high to ensure there is a sufficient quantity of offset credits in the forest buffer account to cover any reversals in the early years. These risk ratings may be decreased or adjusted at a later time, once more data are available on the actual rate of reversals due to various risks and the functioning of the forest buffer account.

N-23. Comment: An error also found in CAR 3.2 is the setting of a default for other Episodic Catastrophic Events. This category was added for places predominately outside of California, where hurricanes, tornado or extreme high wind events occur, so setting this to default at three percent is unfair to California projects and should allow for verifiers to review and accept much lower values for lands not found in these types of high wind event areas. Similarly, in unique areas such as volcano blast zones, [the protocol] should allow for the verifier to add a risk factor. (CAFORESTRYASSOC1)

> **Response:** The risk rating for episodic catastrophic events may cover a variety of risks not accounted for in other categories. At the outset of the cap-and-trade program, there are not sufficient data to determine if all the initial risk values used in determining the forest buffer account contribution are appropriate. However, in the absence of better risk data, we believe that it is important to err on the side of having the risk factors too high, to ensure there is a sufficient quantity of offset credits in the forest buffer account to cover any reversals in the early years. These risk ratings may be decreased or adjusted at a later time once more data are available on the rate of reversals due to various risks and the functioning of the forest buffer account. It is conceivable that these average risk ratings could be made adjusted based on geography, eco-region, and other factors in the future, but it is not possible to conduct such an analysis at this time.

N-24. Comment: The Board of Forestry and Fire Protection (BOF) believes that the primary criteria for any offset project should be the demonstration of additionality, i.e. surplus carbon sequestered or CO_2 removals above what would have occurred without the project. (DFFP1, DFFP2, BFFP)

> **Response:** We agree with the importance of ensuring that all credited greenhouse gas emission reductions and removal enhancements from forest projects are additional, and this is in fact required by AB 32 and the cap-and-trade regulation. The provisions of the Forest Offset Protocol are designed to ensure that all credited reductions are additional.

N-25. Comment : We are writing to strongly urge the California Air Resources Board (CARB) to retain the proposed Cap and Trade rule to include even age management in the carbon offset program, in order to protect forests and the wildlife that rely on them from catastrophic wildfire. Even age management is a proven silviculture practice and is beneficial when implemented under the California Forest Practices rules administered by the California Department of Forestry and Fire Protection. We urge you to stand strongly to support active forest management in California while also sequestering carbon. (FSCNC)

> **Response:** After carefully considering this issue, we decided at the December 2010 Board meeting to retain a range of sustainable forest management practices, including the use of even-age management within specified limits, in the Forest Offset Protocol.

N-26. Comment: Rather than adjust baselines at renewal of crediting periods, apply additionality discount if necessary. The regulations identify renewable crediting periods for forest projects over 30 year maximum intervals. While it may be beneficial to have regular adjustment intervals to update scientific data for projects, CARB should reconsider the adjustment of forest project baselines over these intervals. Due to the permanence obligation of offsets, the project would have a continued obligation to verify reductions against the initial baseline even if new ones are established based on the 30 year updates. Readjusting a baseline at years 31, 61, etc. would have the effect of creating parallel monitoring and verification obligations against multiple baselines, which could be costly and unnecessary. We, therefore, recommend the forest project baselines to be fixed for the duration of the project life to avoid this problem. If CARB determines that additionality has changed over these 30 year increments, it should consider a discount factor to address this issue, if necessary. (NC1, NC2)

> **Response:** We believe that the current baseline requirements are robust, and agree that providing certainty that project baselines will not be recalculated as a condition of a renewed crediting period is appropriate to provide greater certainty for those developing offset projects. A sentence has been added to the protocol to indicate that the baseline for any Forest Project under this version of the Forest Offset Protocol is valid for the duration of the project life, following a successful initial verification where the project receives a positive verification statement. In transition to the latest version of the protocol during renewal of a crediting period, forest projects will need to comply with the latest quantification methods, such as updated forest buffer account risk factors and leakage risk factors. Forest projects will also need to meet any additional requirements related to maintaining and updating the forest carbon inventory, but will not be required to recalculate a baseline.

N-27. Comment: Explicitly include language to avoid any risk of conversion of natural forests. While it is unlikely that forest offset projects could convert a diverse, natural forest to more simplified conditions and still create a quantifiable climate benefit, we recommend the inclusion of explicit language that prevents this scenario. CARB should address this issue by adding language to the Forest Protocol that prohibits the award of credit for projects that would lead to or actually convert natural or diverse forest conditions to more simplified ones. (NC1, NC2)

> **Response:** The Forest Offset Protocol does not provide any incentives for the conversion of a diverse, natural forest into a more simplified structure involving even-age management. The Forest Offset Protocol includes requirements for projects to demonstrate sustainable long-term harvesting practices and places limits on the size and location of even-aged management practices. The Protocol also includes requirements for natural forest management, which requires all projects to utilize management practices that promote and maintain native forests comprised of multiple ages and mixed native species at multiple landscape scales. While it is possible that a forest owner could alter their management practices under the protocol, they must continue to comply with all laws and regulations, and the natural forest management and sustainable harvesting provisions of the protocol.

N-28. Comment: The revised definition of forest owner needs to be clarified with respect to easement holders. The definition asserts that easement holders are not considered a forest owner, but proceeds to define forest owner to include entities that may hold timber rights. However, easement holders may hold timber rights as part of a conservation easement, which creates an inconsistency in the definition. Therefore, the definition does not need to include an explicit exclusion of easement holders. If there are particular sections of the Protocols that should exclude easement holders from obligations of forest owners, those sections should make this explicit. (NC1, NC2)

> **Response:** We changed the definition of "Forest Owner" to remove the exemption of conservation easement holders and will continue to work with stakeholders to evaluate the merits of the suggested edits.

N-29. Comment: It would appear that all forest biomass can be treated as a tradable forest carbon sequestration credit if it is in the forest, but that only the biomass that ends up in finished lumber—but not in energy chips, pulp chips for paper, landscaping amendments—is counted as sequestration for finished products. This imbalance may be corrected if the emission substitution benefits of energy chips used to generate RPS energy are accounted for in a new CAR protocol. (UCB)

> **Response:** Accounting for substitution benefits of biomass power is outside the scope of the Forest Offset Protocol. Please note that combustion of biomass fuel has already been excluded from a compliance obligation in the cap-and-trade program. Providing offset credits for the combustion of biomass within California would lead to double-counting because (as a result of electricity generation being included in the cap-and-trade program) decreases in fossil-fuel emissions from electricity generation due to the combustion of biomass fuel would be already accounted for within the cap.

N-30. (multiple comments)
Comment: The more significant issue is how the project proponent is directed to calculate 'market leakage'. Market leakage occurs when a project produces less of a product and the consumer goes elsewhere to buy a substitute product. A simple example is if a homeowner wants to build a deck but there is less redwood lumber available, then they can do one of three things: 1) build the deck with western red cedar from Canada or Ipe from Brazil, 2) build a patio out of cement, or 3) don't build a deck or a patio. CAR v3 simply asserts that 80 percent of people will do 3) 'don't build" and 20 percent will do 1) 'use imported wood'. This is captured in equation 6.1 and the attached footnote in the v3 protocols. While this is an improvement over the 0 percent market leakage factor in v1 and v2, it is not justified and is far below the only published estimates that appear relevant for the United States. A number of scholarly articles (e.g. Wear and Murray 2004; Murray, McCarl, et al. 2004) estimated a continental-scale leakage factor of 84 percent for west coast conifers from the largest carbon sequestration project ever undertaken—the reduction in federal timber harvests under the Northwest Forest Plan during the 1990s. It is important to point out that none of the market leakage numbers used in CAR v1, v2 or v3 are backed up by any references to

published literature, trade statistics, or official government reports. Simple math (80/16) suggests that the latest CAR formula overestimates the global climate benefits by a factor of 5 for improved forest management projects that involve a reduction in the level of harvested products. This is larger than a rounding error and could serious diminish the credibility of offsets developed in California. Our partners in the Western Climate Initiative will notice the inflated nature of CAR v3 forest offsets since many of them (e.g. Oregon, Washington, British Columbia, Ontario, Quebec) are major wood product exporters. (UCB)

Comment: The BOF supports further consideration of the leakage issue, to avoid the problem of simply re-locating climate impacts. Version 3, which is under consideration, asserts that only 20 percent of the reduced harvest volume in California will result in 'use of imported wood'. That is, reducing harvest in California will reduce wood demand. California is importing over 80 percent of its wood currently. The BOF has identified this as a major issue, and is trying to actively encourage in-state wood utilization to reduce the state's carbon footprint. (DFFP1, DFFP2, BFFP)

> **Response:** The Protocol attempts to conservatively account for the risk of increased emissions outside the project boundary as a result of project activity. To accomplish this, the Protocol assumes 20 percent of the carbon emissions resulting from reduced harvesting will be shifted to harvest on other lands, either from within or outside of California, to meet market demands. Currently, there is little data available on actual leakage rates. The leakage factors in the Protocol can be updated as better data become available.

N-31. Comment: The proposed U.S. Forest Protocol would grant GHG offsets for three types of projects – reforestation, improved forest management, and avoided conversion. This Protocol contains a plethora of very serious flaws. The most serious of these flaws concern the determination of whether any given forest project is additional, i.e., whether the project would have occurred in the course of business-as-usual. For each type of forestry project, the U.S. Forest Protocol established a performance test. If the project meets the applicable performance standard, the project is deemed to be additional. U.S. Forest Protocol at section 3.1.2. (p. 34 of 131.) We have set forth an analysis concerning the common failures of a performance standard approach to determining additionality in the Williams/Zabel Disclosure at pp. 9-11. As detailed below, the U.S. Forest Project Protocol includes a number of these failures that result in include projects which would have occurred in the course of business-as-usual. This is because performance standards of this type are, by their very nature, almost always comparisons to projects which have actually occurred. In a market economy, the most advanced methods quite often give the business using them a competitive advantage. This is why these advanced pieces of equipment and methods are most often “significantly better than average” and “better than common practice.” In a market economy, they are the result of business-as-usual. It violates AB 32’s requirement of additionality to grant offsets to such projects. (WILLIAMSZ)

Response: The performance standard tests in the protocol are designed to provide reasonable assurance that credited GHG reductions or removal enhancements meet the regulatory definition of additionality, which requires that GHG emission reductions or removals exceed any GHG reduction or removals otherwise required by law, regulation, or legally binding mandate; and that they exceed any GHG reductions or removals that would otherwise occur in a conservative business-as-usual scenario. "Business-as-usual" is defined as the set of conditions reasonably expected to occur within the offsets project boundary in the absence of the financial incentives provided by offset credits, taking into account all current laws and regulations, as well as current economic and technological trends.

N-32. Comment: Improved Forest Management and the "Common Practice" Performance Standard: The U.S. Forest Protocol for improved forest management projects contains several different performance standard flaws. It relies on calculations that involve mind-numbing complexity and a series of subjective and unenforceable judgment calls. This protocol also relies heavily on "common practice" as its benchmark for additionality. The entire demonstration of additionality is based upon "estimating baseline onsite carbon stocks" and comparing this to "common practice" on "similar lands" in the area of the project. Since it is impossible to have an objective determination of whether forest management projects are beyond what would otherwise have occurred under this protocol, the offset performance standard clearly fails to satisfy AB 32's requirements that offsets be "real, permanent, quantifiable, verifiable, enforceable, and additional." (WILLIAMSZ)

Response: The complexity in the additionality assessment and baseline calculation reflects the need to have a multifaceted and detailed analysis to ensure that credited reductions are real and additional. The analysis is not subjective, but rather is based on objective criteria clearly defined in the protocol. Improved Forest Management Projects must take multiple factors into consideration when setting the project baseline and establishing additionality, such as current carbon stocking levels and their relation to comparable lands (common practice), historic management practices (high stocking reference), management of other entity forest lands within a logical management unit, financial feasibility of the baseline model, and all legal constraints on the management of project lands. Common practice carbon stocks are taken into consideration in the baseline determination on private lands, but are not the sole criteria for determining additionality. The use of common practice metrics helps to ensure that crediting is conservative by placing a "floor" on the baseline when carbon stocks are initially above common practice, and other factors in the baseline analysis indicate that carbon stocks would otherwise drop below that level in the absence of the project. In addition to this, all forest projects require a commitment to maintain stored carbon for a period of 100 years following the issuance of any credits, subject to ARB's regulatory enforcement authority. Any decreases in carbon stocks relative to the baseline would result in a reversal that must be compensated for. This regulatory obligation to ensure that carbon is stored “permanently” requires a commitment on the part of the forest owner that goes beyond business as usual.

N-33. Comment: Reforestation - “Less Than 10 percent Tree Canopy Cover” Performance Standards: For reforestation projects, the U.S. Forest Protocol allows two possible performance standards, either of which could lead to the approval of offsets. One of the standards is that there is currently less than ten percent tree canopy cover. In this case, the protocol merely states that projects which occur on land that has had less than ten percent tree canopy cover for the last ten years are automatically additional. No analysis, data, or rationale is presented for this determination. (WILLIAMSZ)

Response: The commenter correctly characterizes one way to meet the additionality performance standard requirement for reforestation projects. This approach uses current and past conditions to project a reasonable baseline; that is, if there is currently less than 10 percent tree canopy cover, and the land has been in this condition at least 10 years, then it is reasonable to use this current non-forested condition as the baseline condition, with the expectation that it would persist in the future absent the project activity.

N-34. Comment: Reforestation - Areas with “Significant Disturbance” - Alternative Performance Standards- “Economic Cost Scenario” or “Historical Not Engaged In or Allowed Timber Harvesting”: For reforestation projects which occur on land which has undergone a “Significant Disturbance” (e.g., fire) projects are additional if they either meet one of two performance standard. For the economic cost scenario (set forth in a two page appendix to the Protocol) or if the “Forest Owner has not historically engaged in or allowed timber harvesting.” U.S. Forest Protocol at section 3.1.2.1. The economic cost scenario approach to additionality appears to very heavily rely on data which either does not yet exist or have not been made public. Twice this part of the Protocol states that certain economic information and assumptions can be found in “the lookup table in the Forest Offset Protocol Resources section of ARB’s website.” U.S. Forest Protocol, Appendix E, p. 103. We were unable to locate this section of ARB’s website. In addition, the second test for additionality contains no explanation or number of years which constitute “historically engaged in or allowed timber harvesting.” It is suggested, by example that this qualification would apply to municipal or state parks, but this is made clear or exclusive in the Protocol. U.S. Forest Protocol at section 3.1.2.1. This completely subjective “standard” is neither rational nor enforceable. (WILLIAMSZ)

Response: If a forest owner has not historically engaged in or allowed timber harvesting, then the rationale is that the forest owner would not have either the financial incentive or means to undertake costly reforestation activities following a significant disturbance. The period of historical activities has been left broad and can apply over the course of the entity’s ownership of those lands, which is the most conservative approach. The second test is designed to determine if reforestation is likely to be financially viable, and consequently, part of business as usual. It involves a straightforward and conservative analysis to determine if the net present value for future timber is greater than $0 using standard assumptions (i.e., whether or not a forest owner would likely make or lose money by reforesting the lands). Since most financially investments would expect a significantly positive return, the current approach is conservative in making sure business-as-usual reforestation is not credited. Supporting files and data that will be included on ARB's website at a later date were available for public review at ARB's offices at the Cal/EPA building in Sacramento during the 45-day comment period.

N-35. (multiple comments)
Comment: I would like to urge the Air Resources Board not to exclude federal lands from carbon offset programs, as currently stated on page 9, 10, and 16 of the Compliance Offset Protocol for U .S. Forest Projects (Part V of the Proposed Regulation to Implement the California Cap and Trade Program).

The U.S. Fish and Wildlife Service, in conjunction with private, not-for-profit groups like The Conservation Fund, has reforested and permanently added over 40,000 acres to the National Wildlife Refuge System in recent years, funded almost entirely by carbon offset funding from private sources. These are lands that were historically forested but had been cleared during the last century. Restoring forest cover to these lands will actually increase the rate of carbon uptake and provide a very real (commensurate with scale) benefit in our collective efforts to limit carbon dioxide build-up in the atmosphere. For example, collectively these efforts have led to the sequestration of over 30 million tons of carbon, and three of our "Go Zero" projects with TCF have been validated under the standards of the Climate, Community & Biodiversity Alliance at the gold level (the highest).

We anticipate seeing many more such projects in the future, if legitimate forest carbon offset protocols do not disadvantage federal lands. However, we are concerned that Part V of the Proposed Regulation to Implement the California Cap-and-Trade Program as written does not make federal land eligible for forest offset projects. Though the Climate Action Registry's Forest Protocol made projects on federal lands eligible subject to legislative or regulatory approval, the current proposed regulation has excluded federal projects entirely, including Restoration Projects.

While we appreciate the added complexity of including federal lands in the Forest Protocol, we believe that removing the provision on federal land eligibility sends the wrong message and would discourage investment in these types of programs, not only in California but all across the country as well. Failing to grant eligibility for suitable federal lands would effectively prohibit projects on National Wildlife Refuges to qualify under this offset program, making it more difficult to attract new capital for forest-carbon projects and slowing our existing work in this area. Furthermore, this protocol is likely to serve as a benchmark for future national offset protocols, and we are concerned that they may set a standard for excluding federal lands in offset programs in the future. (USFWS)

Comment: The BOF supports the addition of public land project eligibility introduced in Version 2 of the Forest Project protocol, however we suggest adding language that clearly allows for future consideration of projects on federal lands. (DFFP1)

> **Response:** Projects on federal lands present an added level of complexity that requires further study before ARB may be able to accept such projects. These complexities include questions related to jurisdiction and enforcement authority, ownership of offset credits, and project approval processes. We recognize the large potential for emission reductions and removals on federal forest lands, but believe that offset projects on federal lands necessitate further review and potential revisions to the protocol at a later point. It is not the intention of ARB to discourage carbon sequestration activities on federal lands. We are open to the possibility of reconsidering the eligibility of projects on federal lands if the policy and regulatory issues can be resolved.

N-36. Comment: Early action projects should have the option to transition to compliance offset projects in the short-term and at the conclusion of the Early Action crediting period in 2014. Section 95975(g) of the cap and trade regulation implies that a project cannot seek a renewed crediting period earlier than 18 months prior to the expiration of the crediting period. We recommend that early action projects be permitted to transition into compliance projects as soon as possible. When transitioning early action CRTs to compliance credits, one consolidated verification should suffice for all previous vintage years. For future vintages, ARB and CAR verification requirements should be coordinated to only require one verification. (PFT1, PFT2)

> **Response:** We agree that early action projects should have the option to transition to compliance offset projects, and we made several modifications to the regulation to facilitate this process while still ensuring the integrity of the offsets. New section 95990(k) was added to clarify how early action offset projects transition to Compliance Offset Protocols. New section 95990(k)(2) clarifies that once an early action offset project transitions to a Compliance Offset Protocol it will begin an initial crediting period.
>
> We modified section 95990(f) to streamline the regulatory verification process for early action offset credits. Any verifications conducted under a voluntary program, such as CAR, cannot be substituted for the regulatory verification of reductions used for compliance.

N-37. Comment: ARB's requirement that forest owners commit to restricting land-use for 100 years following the issuance of the last offset credit has not been justified by ARB either as a matter of policy or science. Forest Protocol sections 3.4 and 7. Criteria ensuring permanence of GHG reductions are certainly appropriate, but must be consonant with scientific fact such as the United Nations IPCC analyses. As noted above, because the AB 32 market program is not anticipated to extend beyond 2050 at this time, it is unfair to forest project investors to impose continuing obligations to provide environmental benefits if there will be no corresponding obligation on industrial emitters and no market to compensate forest owners for climate benefits. Because AB-32 program essentially serves as a bridging strategy for decarbonizing industrial and power sectors, it is unnecessary to impose a long tail of legal liability on forest project owners.

In our experience, this arbitrary requirement has become in practice a major obstacle to implementing forest projects, since few landowners are willing to commit land to a certain use for such an extended period for uncertain economic returns. Thus, ARB's policy is deterring beneficial projects and reducing potential environmental and social benefits. Other forest protocols, such as those developed by ACR and VCS do not impose such an unjustified temporal restriction. ARB fails to adequately examine the scientific, policy and environmental bases for this extended requirement, and thus this requirement is contrary to the APA and CEQA. Rather than demanding that land use be restricted for 100-years, the landowner commitment should be commensurate with the length of the regulatory program, and any adjustment for early withdrawal from a commitment should be proportional to the remaining atmospheric benefit of sequestered carbon. (FCC, BLUESOURCE)

> **Response:** Ensuring permanence is essential to the environmental integrity of the entire cap-and-trade program. Because offsets allow for an equivalent quantity of GHG emissions within the capped sectors, the CO_2 stored in biological sinks resting from offset project activities must stay out of the atmosphere for a time period comparable to the emissions they are offsetting. If they do not, the net effect would be an increase in GHG emissions to the atmosphere. Scientific estimates of the atmospheric lifetime of anthropogenic CO_2 emissions are uncertain, as CO_2 is removed from the atmosphere by a number of processes that operate at different timescales. However, 100 years should really be viewed as a minimum time period for maintaining permanence because a fraction of anthropogenic CO_2 is expected to remain in the atmosphere well beyond 100 years as it is gradually removed through processes such as silicate weathering. The period of 100 years is frequently used in international climate change policy as a standard frame of reference for determining global warming potentials and setting GHG emission reduction targets, and consequently the use of 100 years to define the permanence of reductions is consistent with other programs.

N-38. (multiple comments)
Comment: Green Diamond Resource Company supports the proposed Forest Project Protocols. We encourage ARB to pass the protocols to allow forest offsets to become available to the regulated cap and trade market to allow implementation of AB 32.
We would like to request one change regarding treatment of Habitat Conservation Plans (HCP). Green Diamond was an active participant in the development of the working group that developed the Forest Project Protocol Version 3.1. Version 3.1 recognized HCPs as voluntary agreements that were not part of the baseline. Unfortunately, when the CAR Board passed Version 3.2 of the Forest Project Protocol, HCPs were assumed to be binding agreements and therefore part of part of the baseline (see Section

6.2.1.1). This same position regarding HCPs is contained in the protocols that are currently before ARB. We believe this treatment of HCPs may be a deterrent to future HCPs. It is also unfair to the two landowners in the state that voluntarily committed resources and additional protection measures for the benefit of listed species. We therefore offer the following language as an alternative: Verifiers shall review HCPs, CCAs, SHAs, and equivalents under state law (each, a "Conservation Plan") and the accompanying Implementation Agreement (IA) to determine if they contain a termination clause that could be exercised by the property owner without post-termination mitigation measures that would survive the termination and affect the baseline (such as retained habitat above the state or federal requirements without the HCP). If a Conservation Plan may be terminated without post-termination mitigation, the conservation measures in the Conservation Plan shall not be deemed to be part of the baseline for carbon credits. Verifiers shall also review Conservation Plans to determine if any of their measures are mandated by statute or rule and therefore have the full effect of regulation. Verifiers also may deem a Conservation Plan to be a new Conservation Plan that is beyond the carbon credit baseline when the property owner proposes amendments to an existing Conservation Plan that require federal approval after public review and comment on an environmental assessment or environmental impact statement prepared in compliance with the National Environmental Policy Act (NEPA). (GDRC)

Comment: The BOF supports consideration for those landowners utilizing a Habitat Conservation Program (HCP). Version 3 originally recognized HCPs as voluntary agreements that were not part of the baseline. When a later version was passed, HCPs were assumed to be binding agreements and therefore part of the baseline. The BOF would request consideration that the previous treatment of HCPs as voluntary. ARB may be placing a deterrent to future HCPs, as well as unfairly penalizing landowners engaged in enhanced habitat management. (DFFP1, DFFP2, BFFP)

> **Response:** We reviewed this comment in the context of regulatory requirements to ensure that all credited emission reductions or removal enhancements are additional to business as usual. Habitat Conservation Plans (HCPs) and similar agreements are directly related to compliance with Endangered Species Act requirements; while the specific plans may be altered at a future date or the plans terminated by either party, the forest owner's obligations to comply with the Endangered Species Act remain the same. We concluded that Habitat Conservation Plans and Safe Harbor Agreements (SHAs) that are in place prior to or at the time of project commencement should be considered part of the conservative business-as-usual scenario and modeled as a legal constraint in the baseline. The cap-and-trade regulation requires that credited GHG emission reductions or removal enhancements exceed any GHG reduction or removals otherwise required by law, regulation, or legally binding mandate, and exceed any GHG reductions or removals that would otherwise occur in a conservative business-as-usual scenario. "Business as usual" is defined as the set of conditions reasonably expected to occur within the offsets project boundary in the absence of the financial incentives provided by offset credits, taking into

account all current laws and regulations, as well as current economic and technological trends. It is not ARB's intention to discourage future HCPs; on the contrary, when a forest owner enters into a new HCP following project commencement, the baseline does not need be recalculated.

N-39. Comment: There is also a tremendous flaw in the "Reforestation Projects" category. Lands qualify in this category simply by having low tree cover, or having had a "significant disturbance" (such as fire) and which can be "reforested." The average person would ask, what is wrong with that? You take marginal lands that currently don't have "timber" and subject it to "site preparation" and then plant conifer tree crops. The problem is that this type of thinking is not informed by biology or ecology! The so-called marginal lands may be teeming with important habitat for a wide spectrum of plants and animals. It may be providing habitat for species which are currently rare or even threatened with extinction due to lack of habitat. This happens a lot in California because our state has evolved with frequent fire, and many species of plants have disappeared due to quite effective fire suppression that prevents fire from occurring in forest habitats. Also, because fire is actively suppressed, during wildfire suppression activities, forest habitats are bulldozed, subjected to implementation of fire lines, back burning, and massive drops of chemical fire retardants which all have a negative affect on the recovery of the post-fire forest environment, and reduce suitable habitat for species which require fire. But where fires have occurred, sometimes the habitats bounce back with huge flushes of native species, and are rich with native wildlife. Biologists continually locate rare species of plants that have hitherto been thought to be extinct. These sites frequently contain rare species of plants and animals, such as birds and butterflies that require a certain plant community that is increasingly in short supply. The timber industry has a different view of this phenomena. They will normally try to bulldoze the site and replant it (the even aged model) but if, for a variety of reasons, the site is not replanted after ten years, the site may be considered marginal lands if timber is not growing back at the rate and scale at which they would like to see. Sometimes these are lands with large areas of rock outcrops and poorer soils, that don't support rapid regrowth of conifers. Under natural ecological processes, hundreds of years may pass, with such areas slowly growing and building their soils and seed banks. They may never support conifers over time, or perhaps they will—not everything can be precisely predicted in evolutionary time. They may reburn, if left to natural processes. Such random events are the foundation of biological diversity. And there is no scientific credence to the supposition that non-conifer habitats cannot also serve as carbon sinks. Some types of chaparral communities on serpentine soils may contain shrubs that are hundreds of years old. You cannot tell just by looking at them. They are old because they have evolved on soils that are unique, and don't support dense and lush forests. They may grow for hundreds of years without ever supporting a conifer overstory of any significance. These types of lands are the precise suitable candidates you have designated in your protocols for reforestation. Perhaps the ARB staff thought it sounded great when first proposed by the industry. It is hard to argue against planting trees. For the industry, it's a win-win solution. They get to replant and get paid to do it. The lands may never support commercial timber – that won't matter. It will be worth it to them to bulldoze and destroy a vital ecological niche habitat landscape, and plant it to timber where they ordinarily wouldn't be bothered, in order to reap carbon trading credits. You didn't listen to the arguments against such a proposal brought forward by the public. So, here we are—once again, the great environmental leader, the state of California contributes further to the extinction pathway for hundreds of California's plants and animals. The protocols must also eliminate the provision to award carbon credits for conversion of natural areas, simply because they can be replanted. These areas may contain high levels of natural forest early successional species and intact ecological processes that provide ideal habitat for wildlife. The requirement that areas may qualify simply by virtue of lacking high tree cover for ten years, or due to a significant disturbance such as a fire, is absurd and flies in the face of all environmental law and scientific credibility. Post-fire early successional forests are among the most rare forest types left in America today. Incentives to further reduce their presence is a death sentence for countless living organisms. (PARKER)

> **Response:** We appreciate this comment, which highlights that other environmental considerations should be taken into consideration before a forest owner undertakes a reforestation project. Carbon sequestration potential should not be the only consideration in land management, and there is the potential for adverse environmental impacts if lands are managed exclusively for carbon and not for other values. ARB does not have the authority or expertise to regulate forest management, and relies in part on the expertise of other agencies to ensure that forest management activities do not result in adverse environmental outcomes. To this end, the ARB Forest Offset Protocol requires compliance with all applicable environmental and forest management laws and regulations, which would include provisions of the Endangered Species Act and environmental assessments required by the California Environmental Quality Act or National Environmental Policy Act as applicable. In addition to this requirement, the forest protocol's natural forest management provisions require that only native species would be planted in the project area. The forest protocol has robust carbon accounting methodologies that were designed to function in concert with other applicable laws and regulations.

N-40. Comment: In the case of lumber milled from fallen trees, a huge percentage of the wood will never be utilized and will simply disappear as sawdust and will rapidly cycle into the atmosphere as an emission. That percentage has not been averaged into the equations for carbon accounting. These losses occur at various stages of processing, from the forest to the mill, to the lumber yard and to the ultimate destination wherever that may be. Your only factor in accounting for biological decomposition is based on wood storage of 100 years. I assure you that sawdust does not take 100 years to degrade. Most of it will result in carbon emissions within days and weeks. Further, all of the fossil fuel emissions associated with timber harvests, from tree falling, hauling, milling, and transportation to the lumber yard and the subsequent milling and sanding that occurs when the lumber is turned into products are not accounted for at all. I don't think it is accurate to assume that the accounting for these emissions will occur in the energy production end of the equation. Rather, the amount of carbon in lumber must be a NET figure, that is arrived at after deducting the costs of the fossil fuel energy used to produce the lumber. Otherwise, you are simply externalizing the costs—which defeats the purpose of the legislation to reduce GHG emissions and curb global warming. It is also illegitimate to make assumptions about what type of energy is used to power sawmills. Perhaps some of it will come from burning wood waste. Perhaps none will come from burning wood waste. In any event, from start to finish, many forms of fossil fuel powered equipment is used before the wood product is actually turned into something that will be turned into a product that will store carbon. But you do give credit for carbon storage for lumber products, even for lumber that winds up in landfills. This is fraudulent, as there is no credible way to estimate the volume of lumber that is discarded in landfills, or to estimate its origin. It's certainly carbon stored, but not carbon stored that can accurately be credited for use in a cap and trade scheme. In short, on the one hand you are maximizing credit for tree flesh in the form of lumber, but on the debit side, you completely exclude the fossil fuels and waste emissions from the work required to turn trees into products. Because of these, and innumerable other inaccuracies, uncertainties, and opportunities for fraud, the protocols must simply remove the credit for tree carbon stored in the form of lumber. The only legitimate use of forest carbon credit is the credit for trees that are left standing in the forest. No credit should be given whatsoever for lumber, as it is just too difficult to accurate measure, or even to estimate, the true value of such carbon storage. This doesn't mean it doesn't exist. It is simply too hard to accurately measure. And we cannot get this wrong—the future of the planet is at stake. It is far better to incentivize what we know to be real—the carbon storage capacity of our biologically healthy and naturally diverse forests. Recommendation: Eliminate the inclusion of lumber for crediting carbon in the form of lumber products and in landfills. (PARKER)

Response: The methodologies for harvested wood products take into account that only a fraction of the carbon from what is initially harvested is expected to remain stored in the wood products over 100 years, including mill losses and decay from sawdust, short term wood products, and other by-products. Harvested wood product accounting was included in the forest protocol for more complete carbon accounting at the request of many stakeholders. The Protocol recognizes that not all carbon in harvested trees is immediately emitted, and that some fraction remains stored in long-term wood products over a 100-year period. We recognize that there is greater uncertainty in harvested wood product accounting than in other carbon pools within the project area, but the forest protocol makes use of the best available data and factors in accounting for it.

It is true that fossil-fuel emissions from harvest activities are not accounted for in the protocol; these were excluded on the basis that they are not expected to change significantly, or would likely decrease as a result of the project activity (due to incentives from the protocol to increase carbon in live standing trees and harvest less frequently). Fossil-fuel emissions will be accounted for at the fuel supplier or facility level for the types of sources included in the Protocol.

The commenter is mistaken that credit is given for wood products in landfills; no offsets may be issued for increased carbon in wood products entering landfills.

However, for conservative accounting, when the carbon entering landfills decreases, a deduction is applied to ensure there is no over-crediting.

N-41. (multiple comments)
Comment: Definition of Logical Management Unit: In section 6.2.1.1 of the ARB Forestry Protocol projects with initial carbon stocks below regional common practice must compare project stocks with stocks of a "Logical Management Unit" to ensure that project stocks are not significantly lower than similarly managed land under the same ownership. While this is a reasonable approach to ensure that carbon offsets will be additional to realistic estimates of initial onsite stocking levels, the definition of the Logical Management Unit is a concern. Specifically in cases where even aged management is utilized, project owners must identify a Logical Management Unit that has an excessively strict age distribution requirement by area. In many cases land owners will be unable to identify a Logical Management Unit that meets this requirement. It is not clear why a Logical Management Unit must meet strict age distribution requirements since the purpose of identifying this Unit is to ensure that project stocks are not excessively low, and nothing more. Forest projects are subject to extensive requirements related to age class distribution, species composition and harvest unit size. Equator supports these requirements for projects, but urges ARB to remove or modify requirements of this sort for areas outside of the project area. (EQUATOR)

Comment: Under Section 6.2.1.1 the requirements for a Logical Management Unit involve an impossible test as most areas have histories which prevent this uniform distribution by age class, and if there is any necessary test on age class distribution it is already included in the project requirements for Natural Forest Management under Section 3.8.2 and Table 3.2. (CAFORESTRYASSOC1)

Response: We understand the concern that the definition of a logical management unit (LMU) may not be readily applicable to all management situations. However, the forest protocol recognizes this possibility, and offers an alternative approach that is similarly conservative in evaluating whether carbon stocks within the project area are significantly different from the forest owner's broader management practices in the area. In situations where an LMU containing the project area cannot be identified, the protocol requires that an LMU instead be defined by all lands where the forest owner or its affiliate(s) either own in fee or hold timber rights within the same assessment area covered by the project boundary. This alternative definition should be readily applicable in the situation described by the commenter.

N-42. Comment: ARB should issue clear guidance such as the CAR-developed draft "Transitioning Forest Projects Registered Under Earlier Versions of the Forest Project Protocol to Version 3.x." (See Attachment A) Such guidance regarding transitioning earlier projects to the version 3.x forest protocol provides a workable path forward. Particularly for forest projects conducted under version 2.1, there is significant uncertainty about how to transition to compliance protocols. (PFT1, PFT2)

> **Response:** We included provisions for the transition of early action forest projects in the cap-and-trade regulation. This includes specific provisions regarding how projects that commenced under versions 2.1 and 3.0 through 3.2 of the Climate Action Reserve Forest Project Protocol will transition to the ARB Forest Offset Protocol. It should be noted that ARB's requirements differ in some aspects from the guidance issued by CAR referred to by the commenter. In regard to reconciling differences in baseline calculation methodologies between version 2.1 and ARB's protocol, our requirements fully recognize early action offsets through the end of 2014 as ARB offset credits, but require the baseline to be recalculated according to the ARB protocol for transition. Other language in the regulation addresses forest buffer account contributions and reconciling differences in offset project boundaries.

N-43. Comment: The proposed Regulation to Implement the California Cap-and-Trade Program, US Forest Projects: A paired t-test must be conducted to determine whether the verifier sample plot measurements are within the same population as the inventory submitted by the Offset Project Operator or Authorized Project Designee to a reasonable degree of confidence. Because plot monumentation is not required for all projects, the Offset Project Operator has the option of requesting the verification body to install re-measurement plots within the required area, but not at the same plot locations/plot centers. This would allow for the use of an unpaired t-test to determine the accuracy of the inventory. The proposed regulation should allow for either a paired or unpaired t-test to be used to determine inventory accuracy. (SCS)

> **Response:** We carefully reviewed whether to require plot monumentation, and consequently whether to allow use of an unpaired t-test in verification. After a detailed technical review, we determined that forest carbon inventories without monumented plots could be eligible, but that they would still need to pass an appropriate statistical test during verification. We agreed to modify the methodology for evaluating forest inventories where plot centers cannot be located (though it is not an unpaired t-test), and it generally will require more sample plots to be measured and included in the analysis than for inventories with monumented plots to achieve the same level of statistical confidence.

N-44. Comment: For forest projects located in California, the baseline must be modeled to reflect all silvicultural treatments associated with timber harvest plans (THPs) active within the Project Area at the time of the project's initiation. All legally enforceable silvicultural and operational provisions of a THP – including those operational provisions designed to meet California Forest Practice Rules requirements for achieving Maximum Sustained Production of High Quality Wood Products [14 CCR 913.11 (933.11, 953.11)] – are considered legal constraints and must be reflected in baseline modeling for as long as the THP will remain active. Comment: The definition of the word "active" in reference to timber harvest plans needs to be better defined. This term has significance by CalFire that may not be intended (e.g. an active versus approved THP). Clarification is needed to determine if the project would be “active” at the initiation date and for what duration in the baseline modeling. (SCS)

> **Response:** In response to this comment we carefully reviewed the protocol language in light of the requirement’s intent and the broader need to ensure that reductions are additional. We clarified the text to indicate that the baseline must be modeled to reflect all silvicultural treatments associated with “any submitted, active, or approved timber harvest plans (THPs) at the time of the project’s commencement that would affect harvesting and management within the Project Area during the Project Life.” In other words, we consider any timber harvest plan that has been submitted to a regulatory agency, at whatever stage of approval, should be included in the baseline, based on the regulatory requirement for a conservative business-as-usual scenario.

N-45. Comment: The standard error calculation should include all required and optional pools within the project. The current standard error calculation assumes that the majority of the GHG emissions reductions/removals will be generated by the standing live and standing dead carbon pools. The possibility exists for GHG reductions to be generated in higher proportions from other carbon pools (e.g. the soil carbon pool in areas with peat or muck soils) and the current calculation would not take into account this substantial contribution to the project’s GHG reductions. (SCS)

> **Response:** We agree that all carbon pools included in the forest carbon inventory should be included in the confidence deduction standard error calculations, and clarified the protocol text to indicate this. For most projects, there will not be any difference in the calculation, as we have excluded accounting of optional pools, and the standing live and dead tree carbon pools will be the only carbon pools required by these projects. Under some circumstances, such as when soil carbon accounting is required due soil disturbance, the standard error calculations would need to take these carbon pools into account. However, emissions reductions from soil carbon are not expected to be credited under ARB’s forest offset protocol because soil carbon accounting is excluded, except for when intensive site preparation activities occur above a specified threshold, as these activities may result in soil carbon losses.

N-46. Comment: The “High Stocking Reference” for the Project Area. The High Stocking Reference is defined as 80 percent of the highest value for above-ground standing live carbon stocks per acre within the Project Area during the preceding 10-year period. To determine the High Stocking Reference, the Offset Project Operator or Authorized Project Designee must document changes in the Project Area’s above-ground standing live carbon stocks over the preceding 10 years, or for as long as the Forest Owner has had control of the stocks, whichever is shorter. This definition should take into account the possibility that the Forest Owner may have previously owned the forest within the last 10 years but the ownership was discontinuous (e.g. Landowner X owned the land from years 1-7, Landowner Y owned it from 8-9, and Landowner X reacquired it in Year 10/the project start date). The language regarding ownership should clarify the timeframe for the operational control. SCS suggests that the Offset Project Operator should be responsible for operational control at any time during the preceding 10 year period. (SCS)

> **Response:** We carefully reviewed this issue, and agree with the commenter that the most reasonable and conservative approach to address it is to require that the 10-year look-back to determine the high stocking reference be independent of current ownership. This would not only avoid concerns about discontinuous ownership, but would avoid creating incentives or other potential gaming opportunities that may exist if lands could be sold following significant harvests and new owners would be eligible to initiate a forest project without accounting for the high stocking reference. This modification was made in the protocol.

N-47. Comment: ARB would be well-served to be in close communication with the Climate Action Reserve regarding any updates, clarifications, errata that they have developed since version 3.2 of the FPP was approved. A key example of an update would be their soon-to-be-released revised version of Appendix A. (SCS)

> **Response:** We have been in close communication with Climate Action Reserve (CAR) staff, and received technical input and comments from CAR on continuing work on their Forest Project Protocol. However, any proposed changes to ARB's Protocol would be subject to future rulemaking activities after a full public stakeholder process independent of any CAR update activities.

N-48. (multiple comments)
Comment: We express our full support of the proposed rulemaking package including the proposed Forest Project Protocol, with the exception of a few adjustments associated with inconsistencies in the recognition and transfer of some early action carbon credits developed pursuant to the Climate Action Reserve (CAR) protocols. Our Overview Issues are:

- There is a requirement that in the forest projects the verifier must re-measure a minimum number of plots or five percent whichever is greater, the five percent requirement of larger projects is many times over that which is necessary to check the quality of the project effort as long as the plots are randomly chosen, this cost alone could prevent many landowners from participating. As you know, the CAR Board of Directors adopted their revised Forest Project Protocol (FPP 3.2) at their meeting on August 30th after a nearly three-year multi-stakeholder public-input process of creating this protocol. This process and adoption became the basis for your current proposed FFP, which we fully support. The proposed ARB FPP also included a small but important adjustment to the methodology used to select project areas. We greatly appreciate ARB's recognition of this adjustment in your proposed regulatory action. CFA supports this simple adjustment that will help incentivize landowners to preserve mature forests via carbon projects. We would also like to address a critical issue that appears to be the central focus of challenge from several organizations to the FPP rulemaking proposal, that being the use of even-aged forest management (specifically CA's unique approach to clear-cutting) as a critical tool to maximize forest carbon sequestration while fully protecting the ecological benefits of our forests as required by compliance with all state and federal environmental laws and regulations. In this regard, the importance of foresters having the full array of silvicultural prescriptions, including planted native forests via even-aged prescriptions (including clearcuts), for which timber harvesting permits (THP) have been developed by a Registered Professional Forester (RPF), implemented by a Licensed Timber Operator (LTO), after an exhaustive multi-disciplinary environmental review and permitting process equivalent to an Environmental Impact Report (EIR) under CEQA, has led to California having the most powerful forest-related environmental protections of any state in the nation. (CFA)

Comment: There is a requirement that in forest projects the verifier must re-measure a minimum number of plots or five percent, whichever is greater. The five percent requirement of larger projects is many times over that which is necessary to check the quality of the project inventory effort as long as the plots that are re-measured are randomly chosen. This five percent re-measurement cost alone may prevent landowners from participating. A better approach is the approach (developed by a stakeholder work group) taken in CAR 3.2 where the verifier goes through a thorough review and establishes a minimum number of plots based upon project characteristics. (CAFORESTRYASSOC1)

Response: After carefully reviewing this and similar comments, we recognized the need to provide more detail in the Forest Offset Protocol's verification requirements with regard to the measurement and evaluation of sample plots used to develop the forest carbon inventory. We consulted with technical experts on this question and included modified requirements for the verification of the forest carbon inventory that are intended to provide a high degree of statistical confidence while not requiring more plots to be measured by a verifier than is necessary to assure this level of confidence.

In response to this and similar comments, we modified language in the Forest Offset Protocol and cap-and-trade regulation to allow less-intensive (desk review) verification to be conducted in years when a full verification with a site visit is not required. We believe that less-intensive verification as defined in the protocol will be sufficient to provide reasonable assurance as long as a thorough on-site verification is conducted every six years.

In the protocol, even-aged management remains within the scope of Improved Forest Management projects.

N-49. (multiple comments)
Comment: There has been a lot of public comment over the lying dead wood pool and the decision not to make it a required pool. In forests as the stakeholder workgroup correctly determined such a pool is very expensive and they recognized that the source of lying dead wood is predominantly from standing dead wood, a pool that is required to be measured and certain minimums must necessarily be maintained for the natural forest management definition, there is no need to change this decision. (CAFORESTRYASSOC1)

Comment: It is also important that the same workgroup with almost two years of effort developed the standard for when it would be necessary to actually measure soil carbon, another extremely expensive pool to estimate. That process recognized that this pool is virtually not affected by most management activities and only when a site is very drastically disturbed is there any likelihood of loss from this carbon pool, again 25 percent disturbance standard is a reasonable and conservative standard that balances cost without compromising the protocol carbon additionality. (CAFORESTRYASSOC1)

> **Response:** We thank the commenter for their input on this topic. We are not proposing to make any changes but will continue to monitor these issues for potential future updates to the Protocol.

N-50. (multiple comments)
Comment: CARB should also require additional forest carbon pools to be included in the GHG accounting, such as lying dead wood and soil carbon when activities associated with conversion to more simplified forests are undertaken. (NC1, NC2)

Comment: We also recommend that ARB include lying dead wood and soil carbon where there is significant disturbance in the accounting. We realize these were optional pools considered in the protocols in the Climate Action Reserve version and staff was looking to standardization and have required pools. And, therefore, these pools aren't part of the required pools. It is important to include lying dead wood and soil carbon where there is significant disturbance from accurate accounting perspective. And it can also help get at the issues and concerns around conversion. (NC6)

Comment: Need to capture the important carbon pools of lying dead wood and soil carbon to make sure that we are not missing important pieces of the accounting. (PFT2)

> **Response:** It is unclear that conversion to a more simplified forest structure would necessarily result in an associated decrease in soil carbon or lying dead wood. Loss of soil carbon is likely to depend on the intensity of the impact to forest soils, and the protocol already requires that soil carbon be included when intensive site preparation activities such as deep ripping, furrowing, or plowing impact greater than 25 percent of the project area during the project life. The protocol also recognizes that lying dead wood is recruited from the standing dead wood pool, and requires both visual inspections of lying dead recruitment by

verifiers and minimum standards for standing dead wood recruitment that is increased if a verifier observes that lying dead wood in the project area is not commensurate with recruitment from standing dead trees. We also recognize that lying dead wood provides important environmental and ecological benefits, but that quantification methods for lying dead wood have relatively high costs and uncertainties. For these reasons, we consider the current carbon accounting framework and protocol requirements to be sufficient to prevent or account for significant decreases in the lying dead wood and soil carbon pools. We will continue to monitor these issues for potential future updates to the Protocol.

N-51. (multiple comments)
Comment: Amend the forest protocol to include lying dead wood as a mandatory pool inside the GHG assessment boundary. Exclusion of lying dead wood from project carbon accounting facilitates its removal and the attendant loss of ecological benefits. Require the accounting of the soil carbon pool based on particular activities that could disturb the soil and cause emissions of carbon dioxide. Due to the potential for this pool to be a source of emissions under certain conditions and because the tracking of this pool could also capture conversion of natural forests to more simplified ones (i.e., by capturing increased emissions associated with the conversion practice), we urge ARB to include soil carbon as a required pool based on the activities referenced in version 3.2 of the CAR Forest Protocol. The CAR Forest Protocol only requires accounting for soil carbon when site preparation activities involve deep ripping, furrowing or plowing and soil disturbance exceeds 25 percent of the project area. That threshold is very high and could exclude most projects, even those with significant soil carbon emissions. Therefore, we suggest that ARB eliminate that “25 percent of the project area” threshold, and instead require that all projects which employ these high-impact practices, above a de minimus amount of two percent of the project area, be required to measure and report project impacts on soil carbon. (KUSTIN04)

Comment: Improved forest management projects must include the forest carbon pools associated with lying dead wood and, when there is intense site disturbance above certain thresholds, soil carbon, in order to ensure accurate accounting. We appreciate that ARB staff has proposed eliminating the category of “optional” pools in order to improve accounting consistency. As described below, we believe that lying dead wood should be a mandatory carbon pool and that soil carbon should be a mandatory pool if specific forest practices that can significantly reduce soil carbon are employed. As described below, we believe that both of these changes will reduce uncertainty, discourage any possibility of forest conversion from diverse conditions, and help to ensure accuracy at a reasonable cost. We urge ARB to amend the forest protocol to include lying dead wood as a mandatory pool inside the GHG assessment boundary. This pool was required in the prior version of the Climate Action Reserve Forest Protocol. Lying dead wood can be a significant carbon pool that can be significantly changed depending on a forest owner’s management practices. Moreover, lying dead wood can provide important wildlife habitat and other important ecological values. Exclusion of lying dead wood from project carbon accounting facilitates its removal and the attendant loss of ecological benefits. We recognize that adding this pool may increase the cost of measurement. However, while we would support efforts to achieve acceptable measurement accuracy at the lowest possible cost, a potential increase in measurement costs is not justification for inaccurate and incomplete measurement. We recommend that ARB require the accounting of the soil carbon pool based on particular activities that could disturb the soil and cause emissions of carbon dioxide. While certain forest project activities could lead to increases in soil carbon or have little impact on carbon, other practices can cause emissions. This is reflected by the CAR's inclusion of soil carbon in version 3.2 of its Forest Protocol based on activities such as deep ripping or furrowing of the soil, among others. ARB's regulation excludes this pool entirely because it was an optional pool in the CAR Protocol. However, due to the potential for this pool to be a source of emissions under certain conditions and because the tracking of this pool could also capture conversion of natural forests to more simplified ones (i.e., by capturing increased emissions associated with the conversion practice), we urge ARB to include soil carbon as a required pool based on the activities referenced in version 3.2 of the CAR Forest Protocol. The CAR Forest Protocol only requires accounting for soil carbon when site preparation activities involve deep ripping, furrowing or plowing and soil disturbance exceeds 25 percent of the project area. That threshold is very high and could exclude most projects, even those with significant soil carbon emissions. Therefore, we suggest that ARB eliminate that "25 percent of the project area" threshold, and instead require that all projects which employ these high-impact practices, above a de minimus amount of two percent of the project area, be required to measure and report project impacts on soil carbon. (KUSTIN07)

> **Response:** Projects must demonstrate a priori (section 3.8) and through verification (section 9.1) that they meet the definition for natural forest management, including stocking of lying dead wood.
>
> We clarified the language in section 5 that identifies when soil carbon is a required or excluded carbon pool. The previous language had left some ambiguity as to how to evaluate when the 25 percent threshold for intensive site preparation activities that triggers a requirement for soil carbon accounting would be exceeded. Without changing the existing requirement in any way, ARB clarified the language to identify that soil carbon accounting is required when site preparation activities involve deep ripping, furrowing, or plowing where soil disturbance exceeds or is expected to exceed from the baseline characterization and modeling 25 percent of the Project Area over the Project Life.

N-52. (multiple comments)
Comment: The proposed ARB FPP also included a small but important adjustment to the methodology used to select project areas. We greatly appreciate ARB's recognition of this adjustment in your proposed regulatory action. CFA supports this simple adjustment that will help incentivize landowners to preserve mature forests via carbon projects. We believe ARB's proposed FPP is fully consistent with your objective to achieve conservative, high quality offsets that are additional, consistent with CEQA, and

which create significant environmental co-benefits and we strongly support its adoption. (CFA)

Comment: First, I want to say the forest protocol as developed through this multi-stakeholder process is sound. It meets the test of being real, permanent, additional, verifiable enforceable.

And I want to point out one thing in particular, which is that all forest projects under the protocol regardless of the project type are absolutely required to increase and maintain permanently the total amount of carbon stored on the land over time. That is true regardless of the harvest method used. Any tree that's harvested under the protocol is the reduction in the total carbon on the forest and is not credited. I want to make that clear. I want to say that we do absolutely agree that the protocol should not be used to convert native forests to plantations. This is something that we don't believe can occur under the protocol, but we also agree that, as you pointed out, this is an iterative process and refinements can be made. (CAR3)

Comment: The simple message I have for you today is that much of the climate change debate in the world is from the fact that there is planes of different science. And I think what you challenged our work group with was to actually find the science and bring that science forward in a responsible and accurate and concise way. And we did that in the protocol. There is no incentive for even-aged management. So if you clearcut one spot, you have to hold the rest of the forest not only to replace all of those tons but more, to actually create a situation where you get a credit. There is no incentive for even-aged management. So if you clearcut one spot, you have to hold the rest of the forest not only to replace all of those tons but more, to actually create a situation where you get a credit. The protocol deals with even-age management in the most scientifically responsible way under the laws of the state of California. It does not cause any of the effects you've heard today. Otherwise, under CEQA, how could we get a permit to do that that's reviewed by the Department of Forestry, the Department of Fish and Game, and by the State Water Quality Control Board. So we're not causing erosion. We're not causing impacts to wildlife, and we're not harvesting in a non-sustainable way. Secondly, the lying dead wood issue that's been raised before you today, the work group recognized one of the most expensive inventories in the world is to count down material. We also recognize that all down material comes from standing dead material. It has to die and then fall. Our protocol designed the measurement technique to measure the standing dead so that the dying lying dead was accounted for. (PERMANENCE)

Comment: We believe the Air Resources Board's proposed FPP is fully consistent with your objective to achieve conservative, high-quality offsets that are additional, consistent with CEQA, and which create significant environmental co-benefits and we strongly support its adoption. (CAFORESTRYASSOC1)

Comment: We support the forest protocol. I was a member of the work group that met for nearly three years, a multi-stakeholder work group of forest land owners of State and federal agencies of environmental organizations that met every third Friday for almost two-and-a-half years and completely public input process as well. We brought in scientists. The protocol that was developed based upon science. It is fundamentally based on maintaining the high quality protection measures that California has. I've given you a paper there that identifies a number of the more significant protection measures that clearcutting and even age management have. I do want to point out that clearcutting in California is not clearcutting. It's not deforestation. It is, in fact, regeneration. (CAFORESTRYASSOC2)

Comment: As a practitioner of forestry in the sierras for over 30 years, I've used both even aged and uneven aged systems. And I do applaud your recognition of utilizing all of the silviculture systems in your protocol to achieve the carbon sequestration, reduce the emissions, and have sustainable forestry. A salient issue for me is retaining management as a viable silvicultural system. To take that off our book of tools would be a tragedy. We do have a lot of cut-over timber lands. We have disturbance oriented fire eco systems. And we have large fires that occur in the State of California. Whether by design, or Mother Nature, even aged management meets the goals of the state of many lands owners. And with the recognition there are forest practice rules and forest practices acts, CEQA and other guidelines, even aged management achieves distribution of landscape habitat, forest productivity, fuel reduction, and long-term sustainability. (FELLER1, FELLER2)

Comment: There really is no incentive in the rules as stated for any kind of forest deforestation. In fact, the rules only allow the kind of forest residues that would actually promote healthy forests in California. (MORRISG)

Comment: CAL FIRE supports ARB's decision to include the Urban Forest project and Forest Management project protocols for determining eligible emissions offsets under the Cap and Trade program. The protocols as proposed provide detailed methodologies for estimating carbon sequestration and avoided emission credits that are real, additional, permanent, verifiable, enforceable and quantifiable. ARB should not pick winners and losers among forest offset projects based on criteria outside the scope of AB 32, i.e. the offsets should focus on GHG reduction goals. Forest projects that include timber harvesting are already subject to regulation developed by the Board of Forestry and Fire Projection (BOF) and administered by CAL FIRE to protect soils, watersheds and water quality, wildlife and habitats, riparian and lake zones, forest health including pests and disease, and other environmental values. CAL FIRE supports the requirement that each verification team include at least one Registered Professional Forester (RPF) who takes an active role in reviewing the forest carbon inventory program and conducting site visits. (DFFP1)

Comment: We support the adoption of the Climate Action Reserve Forest Protocols as the basis for CARB issued offset credits in the United States. The Protocols have gone through numerous public processes over the past ten years with extensive input from experts, stakeholders and the general public. We appreciate that a number of edits were necessary to transition the Protocols from a voluntary framework to CARB's regulatory one. (NC1, NC2)

Comment: The BOF supports the requirements in the Forest Project Offset Protocol that each verification team include at least one Registered Professional Forester (RPF) who takes an active role in reviewing the forest carbon inventory program and conducting site visits. (DFFP1, DFFP2, BFFP)

Comment: We support the possibility of crediting emission reductions from verifiable reductions of tropical forest destruction and degradation. The current placeholder language on sectoral crediting helps establish some of the fundamental principles that will be needed to ensure environmental and social integrity of this program. However, careful decisions on many more details, which staff is now considering, will be necessary before this program can be implemented. (UCS1, LUDLOW, UCS1)

Comment: The Board of Forestry and Fire Protection supports the inclusion of forest carbon offset projects that produce GHG benefits to the atmosphere. The protocols, as proposed, provide detailed methodologies for estimating carbon sequestration and avoided emission credits that are real, additional, permanent, verifiable, enforceable and quantifiable. The Board also supports the requirement in the Forest Project Offset Protocol that each verification team include at least one Registered Professional Forester (RPF) who takes an active role in reviewing the forest carbon inventory program and conducting site visits. (BFFP)

Comment: The forest protocol meets your objective of providing offsets that are real, permanent, quantifiable, verifiable, enforceable, and efficient. At Sierra Pacific Industries, we are managing our forests for the long term. We're going to be operating under the protocol. We're going to meet the standards. And we're also going to operate and continue to operate under the State's very strict forest practice rules that are developed by the Board of Forestry and implemented by any number of agencies. In short, we urge you to adopt the package that's before you today including forestry protocol. (SPI)

Response: Thank you for your support.

N-53. (multiple comments)
Comment: The OWG encourages ARB to consider and possibly adopt amendments to the ARB Offset Protocol, no later than 2011, permitting the aggregation of small forest projects. (OFFSETSWG1) [Comment 675]

Comment: The staff report for the Compliance Offset Protocol for U.S. Forest Projects (the "Compliance Forest Protocol") highlights that ARB staff decided not to include aggregation rules for smaller forest owners in the protocol at this time, in part due to time constraints related to evaluating the aggregation rules that were very recent adopted by the Climate Action Reserve in August 2010. ARB staff noted that they recognize the significant potential benefits for the environment and offset supply of lowering barriers to participation for small forest owners. We commend ARB staff's focus on the barriers to participation facing smaller forest owners, and we would encourage ARB to incorporate aggregation rules into the compliance Forest Offset Protocol in 2011. Approximately 75 percent of all private forest acreage in the U.S. is held in ownerships of under 5,000 acres. Family forest owners often maintain forests that have higher carbon stocks and older growth stands than industrial forest owners. These older growth forests are at significant risk of harvest and conversion due to financial pressures and estate planning problems faced by the families that own and manage them. At the same time, family forest owners face high upfront costs in developing carbon offset projects and a difficulty in marketing small lots of offsets. Aggregation makes carbon projects feasible for family forest owners by helping them achieve economies of scale while maintaining high standards for carbon measurement and offset quality. Enabling aggregation will be critical to delivering offset supply from U.S. forests and to ensuring that the carbon markets are not accessible only to large industrial forest owners. In our view, the Aggregation Guidelines adopted by CAR in August 2010 do not conflict with any provision of the compliance U.S. Forest Projects Protocol, and incorporating a version of the CAR aggregation model would level the playing field for family forest owners, help protect older-growth forests managed by families, and provide a significant boost to forest carbon offset supply. We hope that developing aggregation rules will be a priority for ARB staff in 2011. (SHILLINGLAW1)

Comment: I want to urge the Air Resources Board to work to incorporate aggregation rules to the compliance forestry protocol. Seventy-five percent of private U.S. forest land is held in land holdings under 5,000 acres, really where the carbon is. Smaller family forests owners often manage forests with overgrown trees and higher carbon stocks that are significant risk to harvest and conversion to non-forest uses. These land owners face high effects of cost and lack economies of scale in developing forest carbon offset projects. Aggregation rules can enable, level the playing field for smaller family forest owners, reducing cost and achieve economies of scale, while maintaining offset qualities. Climate Action Reserve has adopted aggregational audits. And I just want to encourage the Air Resources Board to work in 2011 with that, other aggregation models, and incorporate them into the forestry protocol. (SHILLINGLAW2)

Comment: Intentional reversals that leave carbon stocks above a project's baseline should not automatically trigger project termination, and conflicting language in the proposed regulation and the U.S. Forest Project compliance protocol should be reconciled on this issue. (section 95983(e)(1))

The Compliance Forest Protocol, like the CAR Forest Project Protocol v3.2, requires intentional reversals to be replaced with offset credits at a certain rate that are then retired but does not require the termination of that project following an intentional reversal so long as the project's carbon stocks remain above baseline. Section 7.4 of the Compliance Forest Protocol states that "If a reversal lowers the Forest Project's actual standing live carbon stocks below its approved baseline standing live carbon stocks, the Forest Project will automatically be terminated" but makes no other provision for automatic termination (60). The proposed regulation, in contrast, states in section

95983(e)(1) that "If ARB determines that an intentional reversal has occurred pursuant to section 95983(c), the forest offset project will automatically be terminated by ARB or an Offset Project Registry. We recommend that this language be revised to align with the language in the Compliance Forest Protocol by modifying section 95983(e)(1) as follows:

> If ARB determines that an intentional reversal has occurred pursuant to section 95983(c) and such intentional reversal lowers the Project's actual standing live carbon stocks below its approved baseline standing live carbon stocks, the forest offset project will automatically be terminated by ARB or an Offset Project Registry.

Imposing an automatic project termination due to any intentional reversal makes little sense from an atmospheric integrity perspective and would impose unbearable financial risks on the shoulders of forest owners. Consider a forest owner with an Improved Forest Management project who accidentally removes an extra one tonne from the obligated reductions on the project area, which would constitute a minor intentional reversal. Under the current section 95983(e)(1) language, such a minor intention reversal would cause the entire project to be automatically terminated, forcing the landowner to go to the market to replace a large volume of offsets within 30 days at current market prices as required under section 95985(e), all for carbon that has not actually been emitted into the atmosphere. Because many landowners do have ready access to the large amount of liquid capital it would take to replace a large volume of offsets in 30 days, complying with the proposed regulation as written in the event of a minor intentional reversal would likely lead to the liquidation of the forest to pay the liability – an outcome contrary to the purpose of AB 32.

From the perspective of atmospheric integrity, all that is necessary in the event of an intentional reversal that does not reduce carbon stocks below the project baseline is to replace and retire the tonnes reversed. If five tonnes or 1,000 tonnes of obligated reductions have been intentionally emitted, five tonnes or 1,000 should be replaced and retired. Requiring forest projects to be terminated due to any intentional reversal is unnecessary for the climate, and the financial risk would severely reduce the number of landowners willing to enter into forest carbon offset projects. (SHILLINGLAW1) [Comment 748]

> **Response:** We recognize the significant potential benefits for the environment and offset supply of lowering barriers to participation for small Forest Owners. However, the aggregation rules for forest projects developed by CAR are a separate protocol, and we will need to conduct further review to determine their compatibility with the cap-and-trade program and specific offset provisions.

N-54. Comment: Leakage/Shifting Economic Activity: In some cases, such as in the context of forestry projects, the offsets will fail to appreciably mitigate demand and the polluting activity (such as logging) will simply shift elsewhere. (WILLIAMSZ)

Response: The Forest Offset Protocol includes standard approaches and factors for accounting for potential increases in GHG emissions outside of the project boundary as a result of the project activity. This is known as "emissions leakage." For example, to account for the potential of other forests lands to increase harvesting as a result of reduced harvesting on project lands, the protocol applies a standard factor to annual harvest figures.

We recognize the need to use the most scientifically defensible and up-to-date quantification methods, especially as it relates to accounting for leakage risks. At this time there are relatively few published articles that have explored leakage risks, and while there is broad recognition that the risks of market leakage exist, there is also high uncertainty associated with available estimates. We determined not to modify the factors adopted by the stakeholder workgroup that developed version 3.0 of the Climate Action Reserve Forest Project Protocol at this time, and expect that leakage risk will be one of the areas to be evaluated in more detail and updated based on the latest science when the protocol is updated in the future.

N-55. Comment: Avoided Conversion Projects – Shifting Economic Activity: Finally, for avoided conversion projects (e.g., conversion of forest to commercial, residential or agricultural land), the U.S. Forest Protocol relies very heavily on appraisals of land value in the various land use scenarios. U.S. Forest Protocol at section 3.1.2.3. This approach has two basic problems. First, leaving a forest uncut and unconverted to another use does not necessarily result in fewer GHGs. Forest products exist in a world market. The largest supplier to the U.S. of softwood (used, for example, in building homes), is Canada. If U.S. demand for softwood is not diminished, the forest preserved in the U.S. will almost certainly result in additional timber harvesting in Canada or some other country. This will result in no net decrease in GHGs. In fact, it would like result in a slight increase represented by the fuel it takes to import the timber products. Second, appraising land value is hardly an exact science. Anyone aware of the mortgage meltdown should be aware that appraisals can be manipulated, fabricated, and, essentially, purchased by a self-interested party. Having a "qualified" appraiser, as required by the Protocol, hardly addresses this problem. (WILLIAMSZ)

Response: Please see the response to the comment above regarding leakage. While real estate appraisal may not be an exact science, the purpose of the appraisal is to have objective criteria to use to determine if an area of forest land is at a high risk of being converted to an alternative use, and we believe that it accomplishes this purpose. A real estate appraisal, as required by the protocol, must demonstrate both that the project area is suitable for conversion and that there is a significantly higher market value in the alternative land use. The appraisal must also be conducted by a qualified appraiser in accordance with the Uniform Standards of Professional Appraisal Practice.

N-56. (multiple comments)
Comment: The proposed market rules provide only a 25-year crediting period for forestry projects, which is too short from a commercial perspective, particularly in light of the requirement for a 100-year maintenance period following the last credit issuance. See section 95972; Forest Protocol section 3.3. Although ARB indicates that it will provide an opportunity for renewing crediting periods, it is uncertain whether the eligibility or qualification requirements would change after the initial crediting period. The justification asserted by ARB for the restricted crediting, that it needs to preserve flexibility, is insufficient. ISOR at IX-120. It makes no sense to impose arbitrary restrictions that will make forest projects uneconomical simply to preserve flexibility for ARB to change its mind in the future for unspecified reasons. Indeed, ARB recognizes that "project developers need a guarantee of return on their investment," ISOR at IX-120, but fails to assess the effect of its arbitrary crediting restrictions on investment in forest projects and resulting loss of environmental benefits.

At a minimum, the crediting period for forest projects should be commensurate with the permanence requirement, such that forest projects are not forced to continue to accumulate carbon removals without any opportunity to be compensated for the additional sequestration. Under ARB's current rules, a project that is commenced in 2010 will only be credited for carbon stocks through 2035, and will have no guaranteed ability to sell carbon credits after 2050 upon expiration of California's market program, but will be forced to continue its forest management program for another 100 years possibly through the year 2140. This creates an unfair and arbitrary burden, and raises a barrier to meritorious forest projects and environmental benefits. We recommend that the crediting period for all forest projects be at least through 2050, i.e., the anticipated end of the current AB 32 market program.

In addition, we request that ARB adopt a crediting mechanism that will provide compensation for additional sequestration anticipated from forest projects after 2050 (but within the 100-year permanence period that ARB mandates) such that the forest project owner can be credited during the AB 32 compliance period for the full value of the environmental benefits guaranteed by the project. For example, because the term of the regulated market extends only to 2050 and ARB's Forest Protocol requires that forest owners guarantee permanence of the carbon at least 68 to 100 years past 2050, we propose that ARB allow some significant percentage of the projected carbon sequestration outside the term of the regulated market to be carried forward and credited during the first ten years of each offset project. (FCC, BLUESOURCE)

Comment: Recommendation on Section 95972 and ARB Forest Offset Protocol pages 14, 25 - Increase the Crediting Period for Reforestation to no less than 50 years. By its very nature, a reforestation project would sequester substantially more carbon dioxide in "project year 100" than in "project year 1." In some cases, the project may actually be a positive source of emissions in the first year due to site preparation. A reforestation project, however, will sequester a substantial amount of carbon dioxide as the forest matures. Additionally, the reforested area will provide substantial ecosystem services that would otherwise not occur. There are multiple environmental co-benefits that may be attributed to forestry projects. These include water purification, cooling shade, noise reduction, odor reduction, flood control, waste reduction, pollutant reductions, and many other positive attributes. The OWG has attached as Exhibit 1 to these comments a project summary of a CAR-registered reforestation project that is being conducted at the Cuyamaca Rancho State Park. The summary includes a discussion of the project costs and benefits. This document estimates the sequestration values over 100 years and clearly demonstrates that the environmental benefit to California and the economic incentive to the developer/operator (obtained through the sale of eligible offset credits) can hardly be obtained if a project is terminated after 25 years. The short crediting period may also destroy the incentive to develop a reforestation project because the uncertainty created by a 25-year crediting period may require the developer to recover its total project cost within the initial crediting period. This would likely increase the cost per sequestered ton well beyond the cost of any competing offset project and possibly greater than any allowance price. ARB should acknowledge the scientific, environmental, and economic evidence for increasing the reforestation crediting period to at least 50 years. (OFFSETSWG1)

Response: ARB's requirements regarding crediting periods and permanence are in place for sound technical reasons. It is anticipated that over time, the Forest Offset Protocol will be updated and improved based on science and practical experience. It is complicated both for regulators and market participants to have many different versions of the same protocol in use, so there is a desire for all projects to move to the latest protocols over time. Risk factors related to leakage and forest buffer account contributions are expected to be updated over time, and potentially other requirements related to the forest carbon inventory or verification. We believe that the current baseline requirements are robust, and agree that providing certainty that project baselines will not be recalculated, as a condition of a renewed crediting period is appropriate to provide greater certainty for those developing offset projects. We added a sentence to the protocol to indicate that the baseline for any Forest Project under this version of the Forest Offset Protocol is valid for the duration of the project life following a successful initial verification where the project receives a positive verification statement. In determining the appropriate length of a crediting period, we sought to balance the need for investor certainty in projects and the recognition that forest projects often involve reductions that accrue over a long period of time, with the need to be able to review project eligibility and additionality, and to make improvements to offset protocols at some later date. Economic considerations cannot be the only factor considered. There is no explicit limit on the number of renewals possible for forest projects, so there is the possibility that forest projects can continue to generate offset credits for 100 years or longer if the program remains in place.

Requirements for maintaining permanence are a separate issue from crediting periods. Any GHG reduction or removal that is issued an offset credit by ARB will need to be maintained for the period of time determined by ARB to ensure permanence; in this case 100 years. While the existing cap-and-trade program is initially set to continue through 2020, ARB has a designed a program that can and is expected to continue in operation well-beyond that year. However, ARB cannot consider specific mechanisms beyond the scope of AB 32 requirements at this time.

N-57. Comment: Our natural forests depend on the diversity of age, habitat, and species. We would ask that you can go ahead with three out of the four parts of the forestry protocol that you have. But the last one, clearcutting, is not ready for prime time. It has major issues with how you do the accounting. Which are critical to determining whether or not you actually have additionality, verification of that additionality, and also whether you're permitting leakage. These issues have been put off for future dates by the Climate Action Reserve and they will get to them. But you should not launch it now. So I would ask that you think back to what you're trying to accomplish with this program. That you actually want to sequester carbon, as well as promote good forestry practices. Put off including clearcuts until we've dealt with the issue of base lines of the issue of soil carbon accounting. (SIERRACLUB2, SIERRACLUBCA2)

Response: We agree with the importance of ensuring that all credited greenhouse gas emission reductions and removal enhancements from forest projects are additional. The performance standard tests in the protocol are designed to provide reasonable assurance that credited greenhouse gas reductions or removal enhancements meet the regulatory definition of additionality, which requires that greenhouse gas emission reductions or removals exceed any greenhouse gas reduction or removals otherwise required by law, regulation or legally binding mandate, and that they exceed any greenhouse gas reductions or removals that would otherwise occur in a conservative business-as-usual scenario.

The Forest Offset Protocol includes standard approaches and factors for accounting for potential increases in GHG emissions outside of the project boundary as a result of project activity (emissions leakage). We recognize the need to use the most scientifically defensible and up-to-date quantification methods, especially as they relate to accounting for leakage risks. We believe the forest protocol’s accounting methodology accounts for leakage using conservative factors based on the most recent data available. These leakage factors will be the subject to continued review and considered for updates as new information becomes available.

N-58. Comment: Retain the original baseline for the entire 100-year commitment period—but adjust buffer pool contributions or discount factors based on any new research, information, or changes in regulation that has occurred. Due to the permanence obligation of offsets, a project would have a continued obligation to verify reductions against the initial baseline even if a new baseline is established at the 25 year crediting period renewal. Recasting a baseline at years 25, 50, etc. would have the effect of creating parallel monitoring and verification obligations against multiple baselines, which could be costly, confusing, and unnecessary. Therefore, we recommend the forest project baselines to be fixed for the duration of the project life to avoid this problem. We understand and agree it makes sense to require projects to transition to the most recently approved compliance protocol as a condition of renewal. However, we think that it would more efficient, and provide more certainty, to retain the original 100-year baseline (especially given the fact that it represents an average value), and make necessary adjustments to discount factors and buffer pool contributions as new data become available. Without this baseline certainty, landowners could be deterred from participating in the offset protocol due to the increasing complexity of monitoring multiple baselines. While we expect there to be improved information over time on basic forest carbon accounting, the use of a 25-year crediting period creates uncertainties for landowners who are being asked to make 100-plus year commitments for every ton of CO_2 they sequester. (PFT1, PFT2)

> **Response:** We believe that the current baseline requirements are robust, and agree that providing certainty that project baselines will not be recalculated, as a condition of a renewed crediting period is appropriate to provide greater certainty for those developing offset projects. We added a sentence to the protocol to indicate that the baseline for any Forest Project under this version of the Forest Offset Protocol is valid for the duration of the project life following a successful initial verification where the project receives a positive verification statement. In transition to the latest version of the protocol during renewal of a crediting period, forest projects will need to comply with the latest quantification methods, such as updated forest buffer account risk factors and leakage risk factors, and meet any additional requirements related to maintaining and updating the forest carbon inventory. However, they will not be required to recalculate a baseline.

N-59. Comment: Clarify that the forest protocol does not permit forest offset projects to generate credits for converting a diverse, natural forest to a simplified even-age stand. Conversion of diverse native forests into even-aged forest plantations imposes significant ecological impacts on forest ecosystems. We believe that generating forest offsets in this way is counter to the intent of the forest protocol. In addition, the negative ecological impacts from the simplification of a complex natural system to a simplified one should be considered by ARB when evaluating the overall societal benefits and co-benefits as required by AB 32. While there is a diversity of opinions about what forest practices can reasonably constitute “natural forest management,” we believe it is clear that conversion of an existing diverse native forest to a more simplified forest or plantation will not likely meet the test of maximizing co-benefits. We recommend that ARB amend the forest protocol to explicitly clarify that forest projects that convert existing diverse natural forests to simplified, even-age stands are ineligible to generate offsets. This change does not affect the use of even-age management in forest stands where that is the pre-existing management approach. We believe that the recommended changes clarify the long-standing intent in the forest protocol regarding the conversion of natural forests. We realize this may not be a long- term solution or replace future clarifications on the types of natural forest management that would support AB 32’s requirements to maximize co-benefits. (KUSTIN07)

Response: It is unclear that conversion to a more simplified forest structure would necessarily result in an associated decrease in soil carbon or lying dead wood. Loss of soil carbon is likely to depend on the intensity of the impact to forest soils, and the protocol already requires that soil carbon be included when intensive site preparation activities such as deep ripping, furrowing, or plowing affect greater than 25 percent of the project area during the project life. The protocol also recognizes that lying dead wood is recruited from the standing dead wood pool, and requires both visual inspections of lying dead recruitment by verifiers and minimum standards for standing dead wood recruitment that is increased if a verifier observes that lying dead wood in the project area is not commensurate with recruitment from standing dead trees. We also recognize that lying dead wood provides important environmental and ecological benefits, but that quantification methods for lying dead wood have relatively high costs and uncertainties. For these reasons, we consider the current carbon accounting framework and protocol requirements to be sufficient to prevent or account for significant decreases in the lying dead wood and soil carbon pools.

Livestock Manure (Digester) Protocol

N-60. Comment: The digester performance standard contradicts AB 32 requirement of additionality: The key element of additionality is that the project is additional to what "would otherwise have occurred." The offset protocol for Livestock Manure Digester Projects fails to meet this standard of additionality by having a performance standard that allows all such digesters to be offsets on the basis that a digester "is significantly better than average." Thus, the protocol redefines "what would have occurred otherwise" to include what is already occurring at some facilities. "Data shows that California livestock operations (dairy, in particular) manage waste in a manner primarily in liquid-based systems that are very suitable for digesters. Yet even in these favorable conditions digesters are found on less than 1percent of the dairies," (however, the majority of the farms that currently have digesters are significantly larger than the average California dairy). (WILLIAMSZ)

Response: Even dairies with theoretically ideal conditions for operating a digester (such as, but not limited to, large herds and liquid manure management) are still not installing digesters in any significant numbers. Therefore, it is clear that digester adoption cannot be based on simple criteria such as whether or not the manure is managed in a liquid-based system or the size of the dairy. There are many barriers to adoption (including permitting, financial consideration, and other factors), and considering that digester adoption continues to be very rare, it is by definition "significantly better than average." Furthermore, the scenario for digester adoption does not appear to be changing in the foreseeable future (absent additional incentives), so digesters meet the condition for "what would have occurred otherwise."

N-61. Comment: A December 2009 announcement by the U.S. Department of Agriculture and the U.S. Department of Energy indicates that "Currently, only about two percent of U.S. dairies that are candidates for a profitable digester are using the technology, even though dairy operations with anaerobic digesters routinely generate enough electricity to power 200 homes." The Department of Energy has confirmed that "A biodigester usually requires manure from more than 150 large animals to cost effectively generate electricity. Anaerobic digestion and biogas production can also reduce overall operating costs where costs are high for sewage, agricultural, or animal waste disposal, and the effluent has economic value. In the United States, the availability of inexpensive fossil fuels has limited the use of digesters solely for biogas production. However, the waste treatment and odor reduction benefits of controlled anaerobic digestion are receiving increasing interest, especially for large-scale livestock operations such as dairies, feedlots, and slaughterhouses." (WILLIAMSZ)

> **Response:** The financial costs of installing and operating a digester on an average farm significantly outweigh the financial benefits, therefore digesters are typically not profitable. Contributing factors include the fact that selling biogas or electricity generated from biogas does not receive feed-in tariffs in many states, including California. The market rate or net-metering system relating to the sale of energy (or offsetting energy costs) typically falls far short of the cost of building and maintaining a digester unless grants or renewable energy value-added premiums such as feed-in tariffs are incorporated into the project. Even milk prices can affect dairy digester adoption; an otherwise willing farmer may not be able to secure a loan for building a capital-intensive project like a digester without high enough milk prices to meet bank expectations for debt-to-income ratios, which vary from bank to bank. The lack of financial precedent for digester projects is also an issue for farmers and banks. Economic incentives such as marketable emission reduction credits, favorable utility contracts, or renewable energy incentives will initially be needed to encourage investment in manure digesters and make digester offsets financially feasible. It is also important to note that additionality is multi-faceted and addressed through various methods that analyze factors such as, but not limited to, regulatory compliance, baselines, and anaerobic common practice requirements.

N-62. Comment: The proposed program appears to allow existing digester projects to count as additional to what "otherwise would have occurred." The ARB staff report states, "The proposed regulation also includes a process for offset credits from qualified existing offset projects operating under specific offset protocols to be accepted into the compliance offsets program." This feature means that existing projects—projects that are currently in progress—can be counted as additional to "would otherwise have occurred." The net result is a system that allows profitable, existing projects and approaches to methane reduction to be used to allow emissions above the cap in the allegedly "capped" sector." (WILLIAMSZ)

> **Response:** We are required to design regulations to encourage early action to reduce greenhouse gas emissions and to provide appropriate recognition or

credit for that action (HSC section 38562(b)(1) and (3)). Recognizing and rewarding greenhouse gas emissions reductions that occur prior to the full implementation of the AB 32 program can set the stage for innovation by incentivizing the development and employment of new clean technologies and by generating economic and environmental benefits for California. The offset credits from the existing digester projects are additional in that the voluntary program under which these early credits were issued required the projects at the time of implementation to be additional.

N-63. Comment: The ARB Livestock Manure Protocol Report notes that "The installation of a BCS [Biogas Control Systems] at an existing livestock operation where the primary manure management system is aerobic (produces little to no methane) may result in an increase of the amount of methane emitted to the atmosphere. Thus, the BCS must digest manure that would primarily be treated in an anaerobic system in the absence of the project in order for the project to meet the definition of an offset project." Manure could be, and sometimes is, processed in an aerobic environment, producing little to no methane. An example is that manure can provide valuable fertilizer to farming operations and be used instead of petrochemical fertilizers. However, by creating the offset program, ARB may encourage facilities to first switch from an aerobic to an anaerobic process (and hence increasing methane), so that their farm can qualify to participate in obtaining offsets. This decision could also lead to increased use of petrochemicals and other environmental harm. (WILLIAMSZ)

Response: Although any farm may pursue installing a digester, farms that switch from aerobic to anaerobic management of their waste are not eligible for this protocol's offsets, nor are new farms built in regions where aerobic waste management is common practice.

N-64. Comment: ARB has established a single, ten-year crediting period for Livestock Manure projects. TerraPass recommends that ARB allow Livestock Manure projects to extend crediting through renewals as provided by the cap and trade regulation. (TPI3)

Response: At this time, we plan to keep the ten-year crediting period. The ten-year crediting period balances the need for offset project investment certainty and periodic review for additionality. We may consider extending crediting through renewals as part of a future rule amendment.

N-65. Comment: In the introduction (Section 1), Livestock Manure projects are restricted to dairy and swine farms. In the Project Definition (Section 2.2), the protocol references "livestock" projects, which should include poultry and egg farms. We recommend ARB consider the potential for poultry and other livestock manure projects to be included in this protocol. In addition, TerraPass recommends that B_O and VS values be provided for poultry litter, and therefore explicitly included within the context of the Livestock Manure protocol. (TPI3)

Response: The current protocol is based on typical management practices that produce significant amounts of methane, namely those practiced on dairy and swine farms. Adding additional livestock types would constitute a new protocol because most other animal manure management systems do not produce significant amounts of methane. These additional project types may be explored as part of new protocol development.

N-66. Comment: ARB notes that co-digestion of wastes does not preclude a project from inclusion in the Livestock Manure protocol, a position with which we agree. We also suggest that ARB move quickly to allow co-digestion as a creditable offset stream, as this will allow more projects to be included. (TPI3)

Response: Projects that co-digest manure and other feedstock are eligible to receive offsets from the captured methane from manure only. The current protocol is based on typical management practices that produce significant amounts of methane. Non-manure feedstock is typically not managed in an anaerobic environment, and thus has significantly less associated methane emissions. In addition to few methane reduction opportunities, co-digested feedstocks would constitute a new protocol, in part due to the complexity and variability of non-manure feedstocks. Also, by providing offsets to encourage co-digestion, a new California Environmental Quality Act (CEQA) review process would be required. We believe the benefits are too small to pursue co-digestion offsets at this time.

N-67. Comment: ARB's protocol specifically excludes indirect emissions from electricity consumption by project equipment in footnote #9 of page 10. Following this exclusion, however, in Equation 5.11, are calculations for just such indirect emissions. We request that ARB clarify regulations related to accounting for indirect emissions from the use of electricity. (TPI3)

Response: We agree and have clarified the footnote language regarding indirect emissions from electricity. The protocol does not incorporate reductions in electricity consumption, but it does include increases.

N-68. Comment: The Data Substitution methodology does not refer to missed methane readings at livestock operations. Livestock digester methane readings are only required quarterly. If a quarterly reading is missed, we recommend that the project substitute for the missing data point by taking at least two more gas samples during the reporting period, and using the 95 percent upper confidence level (most conservative) of the annual average methane concentration using all samples from the reporting period. (TPI3)

Response: The protocol states that "for methane concentration substitution, flow rates during the data gap must be consistent with normal operation."

N-69. Comment: ARB needs to provide greater clarity on how project owners and offset project developers should obtain timely clarification on certain aspects of the protocol. (It is not clear whether qualified positive verification statements will allow verifiers to accept deviation from or slight changes to protocols as dictated under certain project specific circumstances). Currently, updates to quantification methodologies have to be made public through a public review and Board adoption process. There are likely to be numerous instances where project owners and developers require clarity on the interpretation of the guidance provided or wish to deviate from the protocol due to some unforeseen event. Waiting for public review and board approval may result in the project missing deadlines prescribed in the regulations. ARB needs to enable verifiers and/or registries to make decisions on deviations and variances within a short-time frame and to specify what constitutes a deviation or variance. (CIG)

> **Response:** We will work closely with our approved offset project registries to provide timely answers to questions raised by offset project developers. ARB will make such guidance routinely available so that all offset project developers have the same information and thus ensure a consistent application of the protocol across the same project types. In having a standardized methodology, we do not allow for deviations from the requirements of the offset protocol, but provide limited opportunity for alternative data collection in the event of unforeseen monitoring equipment breakdown. We do not have a variance process, as such a process could be considered an underground rulemaking when the terms are not clearly defined in the regulation. It would be unrealistic to try and provide such terms that would apply to all cases where a variance from the adopted offset protocol may be needed.

N-70. (multiple comments)
Comment: The requirement to report on a calendar year basis will increase costs for projects which don't begin on January 1st by requiring them to perform an additional verification and will also lead to verification bottlenecks (and likely an increase in prices for verifiers) at the start of each year. This impacts smaller projects and livestock projects in particular, which are unable to shoulder additional transaction costs, more than it does larger projects. (CIG)

Comment: We recommend that ARB allow Livestock Manure projects to verify on a two-year schedule. In addition to ongoing operations and maintenance costs of the digester, the metering system, and the biogas destruction devices, the annual verification has proven to be a large expense for offset projects. (TPI3)

> **Response:** We revised the verification schedule in the second 15-day changes to the regulation. Small offset projects can defer verifications to include two years of offset project data reports.

N-71. Comment: There is no mechanism for updating default values provided in the protocol other than to go through public review and board approval. Some defaults are updated on a regular basis. It is good practice to use the most recent version. This seems unnecessary and ARB should allow project developers to use more recent data if it exists. (CIG)

> **Response:** Updating default values as well as any other numerical or equation-related aspect of the protocol is considered part of the protocol's quantification methods. Changes to quantification methods can be updated through stakeholder input and Board action without having to go through the full APA (Administrative Procedure Act) process.

N-72. Comment: The methane destruction efficiency figure for lean-burn ICE's is overly conservative, out of date (taken in the 1990's) and not consistent with EPA figures. It is prohibitively expensive to use a site specific destruction efficiency figure as the protocol allows (around $5,000 per test per engine) and as any site specific test also needs to be performed on an annual basis it is likely that project developers will be forced to use the default figure of 93.6 percent. EPA guidance from some years ago (see Table 3.2-1 http://www.epa.gov/ttn/chief/ap42/ch03/final/c03s02.pdf - reciprocating natural gas engines) gives a destruction efficiency figure of 97.1 percent and the EPA Draft Manure Management Protocol provides a destruction efficiency of 99 percent. Requiring project developers to use such a low destruction efficiency figure and making it prohibitively expensive for them to use an updated figure unnecessarily penalizes small livestock projects. (CIG)

> **Response:** Destruction devices operating on biogas typically do not operate as efficiently compared to operating on pipeline-quality natural gas, so the biogas destruction efficiency value in the protocol is conservative. If a destruction device being used by a project has manufacturer efficiency specs listed for manure biogas of similar quality and attributes to the project's biogas, then those specs can be used instead of the protocol's default values.

N-73. Comment: Section 6.1.1 requires that field equipment be returned to the manufacturer if it is shown to be outside of a +/-5 percent threshold when calibrated. This is unnecessary and expensive. Some meter manufacturers accept +/- 10 percent threshold as within calibration and acknowledge that a variety of field variables can affect calibration checks. Returning a meter to the factory takes time (and means that no gas flows can be recorded) and is expensive. ARB should ask that the meter meets manufacturer's requirements with respect to calibration checks rather than impose an arbitrary threshold. (CIG)

> **Response:** When equipment such as a gas flow meter is operating outside the +/-5 percent threshold, ARB does not require that the equipment be returned to the manufacturer; ARB only specifies that the calibration must be performed by the manufacturer or a certified service provider for that piece of equipment, meaning that the calibration can be performed in the field or on-site as long as the manufacturer deems it acceptable. The threshold itself has been substantiated through many public workshops. ARB has maintained consistency with the Climate Action Reserve's Livestock Protocol and within ARB programs

such as the Mandatory Reporting Regulation Section 95103 (Greenhouse Gas Reporting Requirements). In the cap-and-trade regulation, Section 95976 specifies that equipment used to monitor emissions from offset projects must be maintained and calibrated as required by the manufacturer at the level of accuracy stated in the Compliance Offset Protocol. Other measurements must be consistent with the applicable offset protocol.

Ozone Depleting Substances Protocol

N-74. (multiple comments)
Comment: NRG is supportive of an offset program that will increase compliance flexibility and help to contain costs associated with GHG reductions. NRG also supports inclusion of an offset protocol based on the destruction of Ozone Depleting Substances ("ODS"). (NRGENERGY)

Comment: Nexant believes a robust and active compliance offset market is essential to reduce the overall cost of the California Cap-and-Trade Program on California consumers. As such, Nexant supports the Air Resources Board's (ARB) efforts to extend the application of the four Climate Action Reserve (CAR) protocols proposed for Board approval to projects in Mexico and Canada.

This will increase the overall supply of offsets, while maintaining the environmental integrity of the system. It would also be a means to support the already close collaboration the State has established with our North American neighbors on important environmental challenges such as climate change. Therefore, ARB should look for every opportunity to extend the accepted CAR protocols. (NEXANT)

Response: Thank you for your support.

N-75. Comment: Page 63 of the PDR includes "Discussion of Concept--Ozone Depleting Substances (ODSs)." ARB is considering allowing offset projects not called out by AB 32 "(such as destruction of ODSs that are no longer in production)." Overall, DOD supports this approach; however, we would note that some ODSs, though no longer produced, still serve a crucial role for critical applications, both commercial and military, as users continue to transition to non-ODSs. This is especially true for halon fire suppressants, such as Halon 1211 (bromochlorodifluoromethane, CF2CIBr) and Halon 130 l (bromotrifluoromethane, CBrF3), for which there are no viable alternatives. Military mission-critical applications on aircraft, ships, and ground tactical vehicles utilize these ODS's, as do civil aviation to protect the safety of the flying public and the oil and gas industry for production in cold climates. We would also note that federal policy requires federal agencies to offer any excess Class I ODS to the DOD ODS Reserve for continued use in military mission-critical applications before they can offer for sale or destruction, in recognition of these ongoing critical uses. Given these critical military mission and civil aviation applications, we recommend that halons not be considered for the ODS offset program until such time that it can be determined that adequate global supplies are available. (USDOD1)

Response: Eligible projects for the ODS protocol do not include ODS substances required for any defense or national security needs that are from federal government installations or stockpiles.

N-76. Comment: The proposed ODS Protocol would grant GHG offsets for projects which collect and destroy ODS from refrigeration equipment containing ODS and from foam which was manufactured using ODS as a blowing agent. Both the ODS refrigerant and the ODS blowing agent must originate from the United States. The ODS Protocol contains two major flaws. These flaws would allow potential project operators to receive GHG offsets for claimed GHG emission reductions which are not additional. In addition, the ODS Protocol's reliance on unverifiable assertions and records generated by the offset project operator would create opportunities for fraud which would be extremely difficult or impossible prove once the fraud was completed.

In explaining how the performance standard of destruction of ODS pursuant to the protocol would be additional, the staff report claims, without providing any supporting citation or materials, that "Data shows that less than 1.5 percent of recoverable US sourced ODS are destroyed upon end-of-life of the [refrigeration] equipment or [foam] material. This indicates that collecting and destroying the ODS is above and beyond common practice and therefore destruction meets the performance standard." In addition, the ODS Protocol assumes that all ODS recovered from refrigeration equipment is reclaimed for further use. The combination of these assumptions is important for claiming that all ODS destroyed pursuant to the protocol are additional for purposes of generating offsets. If ODS removed from refrigeration equipment is not always reclaimed and reused, but for technical and/or financial reasons is sometimes destroyed, the destruction of this ODS would not be additional because it would occur in the course of business-as-usual. Not all ODS recovered from refrigeration equipment is reclaimed and reused. To be used as reclaimed refrigerant, ODS must meet established specifications under Title VI of the Clean Air Act. To be economically viable as reclaimed refrigerant, ODS removed from refrigeration equipment must not be mixed with other types of ODS and must not be heavily contaminated with oils and other impurities. Either of these problems will most often make the cost of bringing the ODS up to Clean Air Act specification prohibitively expensive. These problems regularly occur and a significant amount of ODS removed from refrigeration equipment is destroyed rather than being reclaimed and reused. The ODS Protocol would allow the generation of GHG offsets from this destruction. (WILLIAMSZ)

Response: The documentation in the CAR ODS protocol provides the data and calculations supporting the <1.5 percent of recoverable U.S. sourced ODS are destroyed upon end-of-life. The original data source is ICF International (2009), *Destruction of ODS in the United States and Abroad*, prepared for the U.S. Environmental Protection Agency. Some ODS are destroyed today, but the data shows it is far from common practice. We believe the regulatory verification process and ARB's oversight of the offset program will provide for a rigorous offset issuance process. In the unlikely event that any fraud is found after issuance, ARB retains the authority to invalidate a fraudulent offset and require it to be replaced to maintain the environmental integrity of the program.

N-77. Comment: The ODS Protocol contains two glaring enforcement weaknesses. First, the ODS Protocol requires that both the ODS refrigerant and the ODS blowing agent destroyed in a project must originate from the United States. This requirement is not practically enforceable. Once the foam or refrigerant is destroyed, it will be virtually impossible for an enforcement inspector to verify or challenge the paper records kept by the project operator. Second, this hopelessly flawed reliance on paper records generated by the self-interested project operator is a hallmark of the entire verification “methodologies” in the ODS Protocol. The temptations for a project operator to exaggerate or outright fabricate records will be enormous. If GHG offset prices come close to the offset prices in the European GHG trading program, destruction of a single pound of GHG could be worth nearly $100. Again, once all the real evidence is gone, e.g., the foam and refrigeration unit are in the landfill and the ODS has allegedly been destroyed, there is little, if any, hope of proving the fraud. As with the Digester protocol, the net result of the unverifiable and non-additional offsets that can be created under this protocol is a system that would allow emissions above the cap in the capped sectors. Allowing offsets for ODS destruction from foam may also create additional barriers to passage of appropriate regulations that would require ODS destruction before foam containing these substances could be brought to a landfill. Once an offset activity is profitable, those who are profiting will provide additional resistance to the passage of legislation and/or regulations that could provide an across the board, rather than piecemeal solution. In this sense, the proposed offsets do not meet the standard of additional reductions beyond what would have occurred otherwise. (WILLIAMSZ)

Response: The ODS protocol contains chain-of-custody and point-of-origin documentation that can be used by verifiers to investigate and confirm the source of the ODS. There are no proposed ARB requirements to mandate the destruction of ODS from foam on a local, state, or national level. We believe the regulatory verification process and ARB’s oversight of the offset program will provide for a rigorous offset issuance process. In the unlikely event that any fraud is found after issuance, ARB retains the authority to invalidate a fraudulent offset and require it to be replaced to maintain the environmental integrity of the program.

N-78. Comment: On page 5 of the staff report under “Conservative Accounting”, there appears to be a typo with substantive implications. Modify text as follows:

The default credits range from a low of under 0.20 tonnes of CO_2e credit for <u>each CO_2 equivalent</u> tonne of CFC-11 from building insulation to approximately 0.87 tonnes of CO_2e credit for each <u>CO_2 equivalent</u> tonne of CFC-12 refrigerant.” (EOSC1, EOSC2)

Response: The Staff Report is not a regulatory document and is not updated. We reviewed the applicable protocol and as it is the regulatory document, we found no issues per this section of the Staff Report that required a correction in the protocol itself.

N-79. (multiple comments)
Comment: Currently, GHG offsets for ODS destruction are issued by the Climate Action Reserve ("CAR") for use within the United States. On February 3, 2010, CAR issued an ODS offset protocol for the destruction of both domestic ODS6 and ODS originating in Article 5 countries. The Article 5 offset protocol allows the creation of offsets based only on ODS "listed under Annex A, Group I of the Montreal Protocol and used in refrigerant applications." The protocol further recognizes that "these CFC have been fully phased out of production as of January 1, 2010." Like CAR, the Chicago Climate Exchange ("CCX") has issued a protocol for offset generation through the destruction of ODS, limiting eligible substances to those "whose production has been phased out under the Montreal Protocol."

By design, current offset protocols confine offset generation to the destruction of ODS that are no longer produced, assuring offset additionality. CARB should take a similar approach by allowing the use of offsets that are generated through the destruction of phased-out ODS sourced from Mexico, such as CFCs listed in Annex A - Group I of the Montreal Protocol. Mexico was required to phase out production of these CFCs by 2010, and actually achieved a complete phase-out of CFC production in 2005. Allowing offset generation from the destruction of any stockpiled ODS produced in Mexico before January 1, 2010, will provide significant additional reductions in GHG emissions while simultaneously realizing stratospheric ozone benefits. Further, such an approach would align the proposed regulations with the recently issued CAR offset protocol for the destruction of ODS. NRG requests that CARB include offsets based on ODS that have been phased out in Mexico; by adopting the methodology described in CAR's current Article 5 ODS offset protocol. (NRGENERGY)

Comment: ARB’s proposal to exclude ODS from Article 5 countries would unnecessarily constrain the scope of GHG emissions that could be realized under AB 32. We believe it would be consistent with the general policy to allow for projects that originate in Mexico at minimum. The geographic distance from much of Mexico to qualified U.S. destruction facilities is comparable to distances that would be covered in projects that originate in the U.S. By extending eligibility to Mexico for ODS projects, ARB would not only better insure sufficient offset supply to meet the AB 32 targets, but would also help bring the same co-benefits to Mexico as we will be creating in the U.S. (EOSC1, EOSC2)

Comment: In PART 1, Volume I, III.A.5, four different compliance offset protocols are discussed including destruction of ozone depleting substances (“ODS”) within the United States. PART I, Volume I, III.A.7.c further notes that “Staff plans to evaluate how the four protocols being taken to the Board can be expanded to include projects in Mexico and Canada.” This statement contains the following footnote on page III-11:

"Staff does not intend to evaluate an ODS protocol for offset projects in Mexico because the substances covered under the protocol have not yet been phased out in developing countries."

Our research indicates that this statement is not factually correct. Specifically, the Montreal Protocol requires all Article 5 countries, including Mexico, to phase-out production of all Annex A, Group 1 Substances by January 1st, 2010. These substances include Chlorofluorocarbons ("CFCs") covered under the Proposal. Mexico went above and beyond this requirement, and agreed to phase-out all production of CFCs by the end of August, 2005.

On May 5, 2010, MGM Innova received a letter from Augustin Sanchez Guevara, Coordinador de la Unidad de Proteccion of Mexico's Secretaria de Medio Ambiente y Recursos Naturales ("SEMARNAT") which confirmed the following:

1) Mexico phased out production of CFCs in August, 2005. Since that date, production of CFCs, and imports of feedstock of Carbon Tetrachloride has been banned in Mexico.
2) Since January 1, 2010, Mexico has banned imports of CFCs including for use in Metered Dose Inhalers, as Mexico did not request essential use exemptions for any purpose under the Montreal Protocol.
3) Mexico does not have regulations requiring the destruction of virgin or recovered ODS of any kind, including CFCs.

MGM Innova would be happy to provide ARB with a copy of this letter if more clarification is needed.

While Mexico can still produce HCFC-22, and HCFC-141b which are both considered as potential ODS sourced from foam under ARB's Compliance Offset Protocol for U.S. Ozone Depleting Substances Projects, it is worth noting that HCFC-22 can still be produced in the United States for use in equipment manufactured before January 1st, 2010. Finally, given the important role Climate Action Reserve ("CAR") has served in helping to develop ARB's compliance offset protocols, MGM Innova would also like to point out that CAR's Article 5 Ozone Depleting Substances Project Protocol Version 1.0 is limited to CFCs produced for the refrigerant market, and does not include HCFCs.

It is our recommendation that ARB strongly consider the development of a compliance offset protocol for ODS destruction projects for ODS sourced from Mexico. In line with this recommendation, MGM Innova suggests utilizing CAR's Ozone Depleting Substances Project Protocol Version 1.0 as a proxy for Mexico offset protocol development and a potential source of early action offsets from Mexico. The CAR Article 5 Protocol has stringent point-of-origin documentation requirements, monitoring requirements, and destruction facility requirements. Furthermore, the Article 5 Protocol negates perverse incentives related to production of ODS given the requirement that ODS be produced prior to the Montreal Protocol phase-out date. A Mexico ODS destruction protocol has the potential to deliver significant environmental benefits given the high global warming potential of CFCs. Finally, drawing upon its extensive experience working as a consultant across a wide range of emission reduction projects located in North America, MGM sees a significant risk that the compliance protocols currently listed on the Proposal will not be able to produce the quantity of offsets anticipated by ARB. The inclusion of a Mexico ODS protocol and other project types that meet ARB's environmental integrity standards will mitigate the risk of offset supply deficiencies. (MGMI)

Comment: Nexant believes ARB should extend the protocol for the destruction of Ozone Depleting Substances (ODS) to projects beyond the U.S., including projects in Canada and Mexico. However, ARB has indicated in its Staff Report that it does not intend to make this extension to projects in Mexico. The reference is made in a footnote, and is as follows:

"Staff does not intend to evaluate an ODS protocol for offset projects in Mexico because the substances covered under the protocol have not yet been completely phased out in developing countries."

This statement, in fact, is erroneous. Under the Montreal Protocol, ODS production is completely phased out in all Article 5 countries by January 01, 2010. Mexico has ratified the Montreal Protocol and is listed under the Protocol as an Article 5 country. Correspondingly, Mexico has completed phase out of ODS production. Therefore, projects that destroy ODS in Mexico after January 01, 2010 can be considered additional under the requirements set forth in the Staff Report.

In the interest of disclosure, Nexant has invested in offsets to be originated from ODS destruction projects in Mexico. Nexant's investments were made to facilitate the flow of capital to these types of projects after a protocol for the destruction of ODS in Article 5 countries was adopted by CAR.

Although not itself a regulated entity under this program, Nexant's activities in this market serve as a vital source of early capital for carbon offset projects. Our investment in these projects ensures a robust and early supply of offsets, which enhances the cost containment benefits of the offsets component of the Program.

Taking the above under consideration, Nexant encourages ARB Staff to consider the extension of the CAR U.S. ODS destruction protocol to qualifying projects in Mexico. In any case, Nexant highly recommends ARB delete from the Staff Report the footnote referenced above. Taking this action will eliminate the considerable uncertainty of the potential qualification of post-2009 Mexican ODS projects for compliance under the California Cap-and-Trade project. This uncertainty has the effect of eliminating a high-quality and low-cost source of offsets, which would ultimately contribute to controlling the cost of the Cap-and-Trade Program to the State's consumers. (NEXANT)

Comment: While this protocol initially applies only within the United States, the proposed regulations also state that CARB staff plan "to evaluate how the four protocols being taken to the Board can be expanded to include projects in Mexico and Canada."

However, this proposed expansion is then apparently limited in the context of an ODS offset protocol by the following footnote:

“Staff does not intend to evaluate an ODS protocol for offset projects in Mexico because the substances covered under the protocol have not yet been completely phased out in developing countries.”

NRG believes that this limitation is in error because ODS substances covered by current ODS offset protocols were phased out by Mexico in 2005, under the Montreal Protocol and corresponding agreements. In addition, Mexico's importation of CFCs ceased on January 1, 2010, inclusive of metered dose inhalers, because Mexico did not request an essential use exemption for any purpose. Accordingly, NRG hereby requests that CARB remove footnote 35 from the Proposed Regulations, which appears erroneous and unnecessary in light of Mexico's phase-out of CFCs in 2005. (NRGENERGY)

> **Response:** The footnote was inadvertently included in the Staff Report; however, we are not including ODS from Mexico in the protocol at this time. However, as part of ARB’s commitment to provide an increased pool of compliance-grade offsets and expand existing and explore additional protocols, we may consider including the destruction of ODS from Mexico to the ODS protocol at some point in the future.

N-80. Comment: It is our experience, and those of our partners, that in fact, CFC-113 is still in use and in circulation, not as a solvent, but as refrigerant used in cooling systems. There are opportunities to collect the R-113, but as of now, the only incentive is to recycle it back into older equipment. Based on the fact that there is continuing demand for CFC-113 refrigerant, most if not all of the CFC-113 that is being destroyed would very likely be solvent. The EPA Vintaging Model uses the same annual leak rate for R-113 as for CFC-11. Thus, to calculate the baseline emissions from recovery and resale of R-113, the same 10-year cumulative emission rate (89 percent) that is used for CFC-11 can be used in the protocol. (EOSC1, EOSC2)

> **Response:** We agreed and modified the protocol to include CFC-113.

N-81. Comment: In Section 2.3.1 of the draft Protocol (page 5), it is stated that “ODS extracted from a foam source for use in refrigeration equipment is not considered part of this source category, and must instead be considered as a foam source.” We believe this proposed decision does not reflect newly available technologies that change business as usual and would increase, not decrease, GHG emissions that could otherwise be prevented. This proposal is based on the assumption that the usual practice is that ODS blowing agent will be disposed of, still entrained in the foam. In reality, the actual baseline for CFCs that are extracted from foam will also include re-sale for use as refrigerant and eventual release to the atmosphere. Since the CAR protocol was finalized, technology has continued to be deployed, in response to market demand, that extracts ODS blowing agent from foam. The extracted ODS is in pure form and technically and legally eligible for sale and use as a refrigerant. As a result, there is a new "business as usual" where the extracted ODS will be reclaimed and used to recharge older air conditioning equipment to meet demand as this would provide the highest value for the ODS. This proposed eligibility limit makes it uneconomical to carry out destruction projects for extracted blowing agents and therefore will constrain GHG reductions and discourage implementation of innovative technologies. (EOSC1, EOSC2)

> **Response:** The eligibility limit will remain the same at this time as we believe that the technology appears to be in its infancy and not yet a common industry practice. We may consider revising the protocol in the future as part of our commitment to expand existing protocols in order to provide additional projects that would help meet compliance obligations.

N-82. Comment: In Section 2.3.1 (page 6), it is stated that "ODS sourced from federal government installations or stockpiles is not eligible under this protocol." There is no regulatory requirement, Executive Order, or other federal policy that addresses CFC refrigerant still used in operating equipment. In fact, it has been the policy of the federal government, as administered by the U.S. EPA, to encourage continued, responsible use and recycling of ODS refrigerants to maintain the installed equipment and infrastructure. The CAR protocol should have been more precisely worded to make this distinction. Without this correction, the federal government will be forced to incur expenses to destroy CFC refrigerant, or to continue using older, inefficient equipment, instead of being given the option of realizing short-term and long-term savings through early retirement of this older equipment and participation in projects that can generate GHG emission reduction offsets under this protocol. (EOSC1, EOSC2)

> **Response:** Federal government policy indicates that federal agencies should provide all recovered ODS to the Department of Defense, who will bank the substance for any defense or national security needs. Currently, we find that the Department of Defense has a policy to destroy the ODS if there is no need for it. Therefore, we will not include any federal government ODS because the destruction would occur anyway, resulting in no additional reductions.

N-83. Comment: The Laboratory Analysis (Footnote #10 on page 29) specifies where the project developer is the destruction facility itself, a 3rd party should take samples. We recommend that similarly, if the project developer is, or operates an AHRI-certified laboratory, that a different AHRI-certified lab not affiliated with the project developer must be employed to take and analyze the samples. (EOSC1, EOSC2)

> **Response:** No change is needed, as the ODS protocol already includes this requirement.

N-84. Comment: Under Section 5.2.4, facilities that do not have a RCRA permit must document that their operations are consistent with the TEAP requirements. For consistency with other provisions of this proposed protocol and the general regulatory requirements under AB 32, we suggest that this demonstration be certified by a third party. (EOSC1, EOSC2)

> **Response:** We agreed and modified the protocol to clarify that a third party must verify that the facility is in compliance with TEAP.

N-85. Comment: An assessment of the CAR US ODS protocol that deviates in a detail but in a revealing manner from that protocol as published by the CAR: What is Appendix E in the protocol published by CAR became Appendix A in the Staff Report and this Appendix A omits the first page, what is page 76 in the CAR version. Possibly it did not seem important to ARB staff but this page contains a number of significant factual errors with a profound bias. This bias consists of an oriented interpretation of the technology-specific threshold sought in CAR. What is labelled a technology-specific threshold is rather a regulation-pre-emption threshold. (GRAMMIG)

> **Response**: We did not include several Appendices and other background data in the ARB protocol because we considered the information as purely background. For those seeking background information, we provided a reference to the CAR protocol.

N-86. Comment: CAR invented Foam Recovery Efficiency and Calculations that have no technical or engineering content but that allow offset project operators to measure for their preferred result. (GRAMMIG)

> **Response:** We based the foam recovery efficiency calculations on samples and use a similar methodology for industry and international methods.

N-87. Comment: CAR US ODS protocol cites only one source of empirical data, from authors Scheutz, Kjeldsen, and Fredenslund from the Technical University of Denmark. Their research was funded by the EPA and the Association of Home Appliance Manufacturers (AHAM) and consists of measurements in four shredders in Tennessee and a landfill in North Carolina in 2004. Nowhere is it considered whether this data is representative for the other 50 states of the US (some states enforce regulations that old refrigerators should not be landfilled, others cannot because there are no shredders or only those with particular refrigerator relevant problems, and so on). AHAM's members might have reasons to be content with these limited results because AHAM wants to avoid any cost to its members from the environmental leftovers from their products and thus the lowest level of ODS emissions from all appliance disposals could be suitable for them. Why did AHAM choose a Danish research group, far away from the sampling sites, instead of laboratories in the US?

Years later, the average result 14.9 percent from eight refrigerator units becomes the threshold by using it to calculate a baseline for CAR. The Montreal Protocol has in the meantime accumulated much studies and research and the EU has several years of comprehensive data from the implementation of Directive 2002/96 known as WEEE, but these do not appear anywhere in CAR, instead only what AHAM paid for. (GRAMMIG)

> **Response:** The data are based on studies using American refrigerators. The data for ODS released from European appliances during shredding is not applicable because European appliances are subject to different regulations and markets. The Reserve's research indicates that U.S. appliances are larger, have a greater quantity of foam per appliance, and a higher concentration of CFC foam-blowing agent in the foam. Additionally, we found that using a lower emission rate in the baseline is more conservative.

N-88. Comment: On the omitted page 76 in the CAR published version, it is stated that "existing international standards benchmark best practices" and thus "do not provide a mechanism by which to calculate losses of ODS that may occur during the project activity."

It seems that "existing international standards benchmark best practices" should fit well what CAR wants to establish, a technology-specific threshold. Additionality is what is better than what happens elsewhere. If additionality is only defined intra-US, then still the approach to calculate the benchmark is possibly the best approach irrespective of where the bar is put. (GRAMMIG)

> **Response:** The protocol looks at common practice within the area for determining the baseline and what will occur in absence of the protocol. The project activity is also based on what actually occurs, not the best practice, as the best practice would not accurately reflect reductions.

N-89. Comment: CAR argued in the introduction to its Appendix E that European practice is not transferable to justify that good monitoring is not needed, since they have measurement results from eight refrigerators. This excuse was happily accepted by those who made the CAR US ODS protocol, but they did not consider the technology (recovery, recycling, demanufacturing or any treatment of old appliances), they pursued the interest of project developers.

The reasoning to discard the WEEE and RAL recycling standards was useful for CAR but would obviously render the claims from ARB that it is a technology-specific threshold sound hollow (therefore page 76 was taken out). (GRAMMIG)

> **Response:** As with all protocols included in the cap-and-trade regulation we removed background information that is unnecessary for quantification or project implementation from the protocol. The ARB protocols are regulatory documents, and background information, while informative, is not typically included in regulatory language.
>
> As mentioned in response to earlier comments, we used data for appliance measurements for the U.S. due to differences in appliances between the U.S. and other countries.

N-90. Comment: AHAM funded a small sample could have reduced the ODS emission estimation, now it is going to reduce the investments in recycling technology by excluding it from carbon trading. (GRAMMIG)

> **Response:** This protocol is specific to ODS destruction, not ODS recycling, which is business-as-usual and would not result in additional reductions.

N-91. Comment: A further problem for ARB, if WEEE and RAL standards are used in Europe, why do these standards not use the measurement approach from the Scheutz, Kjeldsen and Fredenslund ?

The avoidance of monitoring by CAR was covered by requiring a measurement of ten refrigerators once in the project lifetime. ODS content in foam varies between refrigerator manufacturers. It is false that more than ten appliances results in a higher calculated recovery efficiency (second para on page 43). The real reason for the low sample size of ten is that one can then choose those 10 appliances with the ODS content that gives the lowest baseline and thus maximises income.

Besides, the claim that ten is a minimum required and above ten results in a higher average is simply illogical. How can there be any technical reason for the sample size ten? There is no justification possible for this size. CAR did not relate it to any published study. Was ten simply chosen because it is similar to the analysis that AHAM paid for? (GRAMMIG)

> **Response:** As stated in the Appendix, the methodology uses an approach similar to that utilized by the Waste Electrical and Electronic Equipment Directive (WEEE), RAL Quality Assurance Association (RAL), and other internationally recognized standards.
>
> Regarding sample size, we cannot determine the commenter's reference of sample size, as there is no mention of sample size on page 43 of the CAR protocol, and the mentioned sample size of 10 earlier in the document is for building foams.

N-92. Comment: Another indication for this is that the whole Appendix A is superfluous, as a little bit of fractional algebra shows. It is really simple:
on page 19 in the equation for $BA_{app,i}$

- insert in place of the ratio for Recovery efficiency RE the expression "BA_{post} / BA_{init}" (as page 44)
- insert for BA_{init} the fraction above on page 44.

Since BA_{post} and $Q_{recover}$ in the equation $BA_{app,i}$ is really the same variable, it is mathematically correct to cancel out what is before the bracket and what is in the bracket in the equation $BA_{app,i}$. What is left is

$$BA_{app,i} = Q_{recover} + (Foam_{res} * BA_{conc} / (1 - BA_{conc}) - Q_{recover}$$

Thus the whole exercise of Appendix A is futile. It doesn't add anything to the emission reduction calculation.
$Q_{recover}$ = Total quantity of ODS foam blowing agent recovered during processing and sent for destruction (page 19)
BA_{post} = Quantity of recovered blowing agent in concentrated form (page 45)
Just the words are a little different, it is the same variable.

Appendix A is mathematically meaningless and it is technologically irrelevant because there is no relation between a sample of ten and the average of thousands of appliances. The sampling is meaningless for the calculation and it says nothing about the environmental integrity of the appliance treatment. (GRAMMIG)

> **Response:** The first equation provides a way to calculate the recovery efficiency. The set of equations allows one to make measurements and plug them into the equations to determine the quantity of ODS foam agent prior to treatment. The measurements in Appendix E help determine the following: (1) mass of foam recovered, and (2) the initial concentration of blowing agent in foam; both help determine the initial concentration of blowing agent in the appliance. All the preceding measurements in total help determine the recovery efficiency and then the amount of ODS in the foam prior to any treatment.

N-93. Comment: The Appendix A was invented after the public comment period for the CAR US ODS protocol ended. The November 20, 2009, public draft version 1.0 did not contain it. Nobody in the public workshop on December 7 could have known what was suddenly sprung with the January 2010 version as Appendix E. What the sampling really is, the entire reason for its inclusion in the CAR US ODS protocol, is that it creates the appearance of a technology-specific threshold.

In the clarifications from CAR "Frequency of the Recovery Efficiency Calculation" it states that the recovery calculation must be done once for each project. It doesn't matter whether it is done every day or once in a year, it makes no difference to the emission reduction calculation. Specifying once per project simply creates the impression that it is technology-specific. It actually is specific to nothing.

The sole purpose of Appendix A is to pretend that CAR US ODS is consistent with international standards, while it denies the existence of WEEE and of RAL and denies their technical and environmental properties. (GRAMMIG)

> **Response:** As shown in the response to the previous comment (GRAMMIG), the equations and measurements do provide necessary information. The protocol does not deny the existence of WEEE or RAL but notes those standards and explains why they are not useful for the purposes of a U.S. protocol (e.g., different refrigerator types and different amounts of foam and ODS agent).

N-94. Comment: Because the CAR US ODS protocol has no content that would be in any way related to recovery technology, the design principles behind the whole cap-and-trade are severely weakened in that protocol. CAR aims to "stimulate investment and reward innovation" but the CAR US ODS protocol simply credits any destruction of ODS, no matter where or how much ODS is actually around. Then CAR aims to "be consistent with established international standards." Instead, CAR US ODS rejects the analysis, the data, and the technology reflected in international standards. (GRAMMIG)

> **Response:** Recovery of ODS is common practice (as shown in Appendix B of the CAR protocol), and thus would not provide any additional reduction beyond existing baseline calculations. The protocol only provides reduction credits for reductions above and beyond those achieved through recovery of ODS. The protocol requires measurement and analysis of ODS in foams and refrigerants and the analysis must be conducted by a third party.

N-95. Comment: It is unclear in section 95990 and in the conflict of interest provisions (e.g., section 95979(b)(4)) if offset credits registered with a third party offset program can be or cannot be verified by the same verification body that originally verified the project under the third party program. (EOSC1, EOSC2)

> **Response:** Section 95990(f) was modified to clarify the requirements for regulatory verification of early action offset projects. New section 95990(f)(1) includes new requirements that the verifier performing the regulatory verification services must be different than the one that did the initial verification for the Early Action Offset Program. This ensures that the review is completely independent and unbiased.

Urban Forests Protocol

N-96. Comment: The proposed Urban Forest Protocol would grant GHG offsets for tree-planting and maintenance programs carried out by municipalities, educational institutions, and utilities. This Protocol is the most benign, and probably the most well-intentioned, of the proposed offset protocols. However, even the Urban Forest Protocol contains one serious flaw. The Urban Forest Protocol assumes that any "Net Tree Gain" represents an additional reduction in GHGs. While any Net Tree Gain is a happy thing for the environment, people, and the livability of our communities, these gains do occur in the course of business-as-usual. A case in point is the urban forest project carried out by San Francisco's Department of the Environment. In its September 2009 Annual Report to the Mayor and Board of Supervisors, San Francisco's Urban Forestry Council noted that a five-year plan, initiated in 2004, had resulted in the planting and maintenance of 26,408 trees. This occurred well before the incentives of GHG offsets. (WILLIAMSZ)

> **Response:** Performance standards are set at levels which represent beyond business-as-usual performance for the entity type. Net tree gain (NTG) is the difference between the number of trees planted minus the number of trees

removed. The analysis of tree planting and removal rates in 18 U.S. cities was used to inform setting the municipal performance standard for NTG to zero, representing a stable urban tree population. Numbers of trees planted in excess of removals qualify as offset project trees, provided all other program requirements are met. Moreover, the performance threshold is not tailored to individual cities, but rather represents a broad-based threshold for beyond business-as-usual performance.

N-97. Comment: Ultimately, for an offset protocol to have integrity, the results of all offset projects must be the result of the financial incentive. It this is not the case, the financial gain for the "would-have-happened-anyway" project is merely a gratuitous reward. While cities and other institutions would appreciate the extra revenue for planting and maintaining trees they would have planted and maintained anyway, the problem is that all non-additional GHG offset will inexcusably undercut the goal of the associated environmental program, reducing emissions. Any such non-additional offsets, will result in allowing additional unjustified emissions above the cap in the capped sectors. (WILLIAMSZ)

Response: The designation of project (additional) versus non-project (business-as-usual) trees and monitoring for resource-shifting (leakage) are unambiguous in the protocol and verifiable on the ground. There is little likelihood that offsets generated under the protocol would constitute gratuitous reward for business-as-usual municipal activity: Despite one-time initiatives such as the Trees for Tomorrow campaign, municipal resources are typically insufficient to address ordinary needs for tree planting, maintenance, and removal.

O. MISCELLANEOUS

This section includes responses for comments that either do not fall within the other comment categories, or that do not directly pertain to the regulation. Major topics concern whether California should implement a cap-and-trade program without partnering with other jurisdictions, arguments to repeal AB 32, making emitters accountable for their emissions, and the validity of climate change and/or climate science.

General

O-1. Comment: I am writing as a California citizen who remembers how hard it sometimes used to be to breathe in California when I moved to San Diego in the early 1970s. When scientists pointed out the sources of that problem, the politicians and agencies of the time took steps to correct it. I am extremely grateful for that and hope you will let scientific findings concerning pollution and global warming guide you in taking further measures to ensure health and livability in our state. I support the views on this issue presented by the Union of Concerned Scientists. (GAGE)

> **Response:** We acknowledge your comment. Please refer to responses directed to comments submitted by Union of Concerned Scientists.

O-2. Comment: Follow the guidelines put forth by environmental protection groups such as the Union of Concerned Scientists, Sierra Club, Green Peace, Friends of the River, Save the Salmon-Columbia and Snake Rivers Campaign, Surfrider Foundation, Center for Biological Diversity, National Wildlife Federation, Scripts Institute, all major universities and others. I agree with and support the recommendations put forth by these groups. (GIANNI)

> **Response:** We acknowledge your comment. Please refer to responses directed to comments submitted by Union of Concerned Scientists, Sierra Club, Greenpeace, Friends of the River, Save the Salmon-Columbia and Snake Rivers Campaign, Surfrider Foundation, Center for Biological Diversity, National Wildlife Federation, Scripps Institute, and all major universities.

O-3. Comment: ANZA fully supports and adopts by reference the comments submitted by AEPCO on this proposed regulation. (AEC)

> **Response:** We acknowledge your comment. Please refer to responses directed to comments submitted by Arizona Electric Power Cooperative.

O-4. Comment: First, if you are so sure what you are doing is right, then there is no reason not to give people more time to respond to your program. You will only need to give this plan the bums rush if you know in your hearts it is wrong. Second, don't you know Global Warming is a huge scam? Wake up and look around; you are the only western state still moving on this; are you crazy? At the very least, you should give more time for public debate. (STERWARTM2)

> **Response:** Climate change poses a serious threat to the economic well-being, public health, natural resources, and California environment. Assembly Bill 32 (AB 32) includes specific timelines for the Air Resources Board (ARB) to develop and implement strategies to achieve the greenhouse gas (GHG) reduction limit established in the law. California is working with other states, jurisdictions in the Western Climate Initiative (WCI), and the federal government to encourage the reduction of GHGs.

O-5. (multiple comments)
Comment: I was never one to believe that cap and trade would really solve the problems of climate change. There is generally not enough political will to set caps low enough and an abundance of political will for giving some polluters a get out of jail free card. If either of these happens, it will have been an interesting exercise, an example of what not to do next time. It is clear that the Republican Majority in the House of Representatives will prevent substantive action from happening at the federal level. California must not fail in showing what can be done. (ROLLEY)

Comment: Carbon trading in general would be counterproductive as a component of AB 32 because it selects for delay in addressing structural change in those industries where it is most important. (CORNERHOUSE)

Comment: Cap and trade is fundamentally flawed because it rewards the state's biggest polluters by giving them free credits. A far better approach to reducing CO_2 emissions and supporting our economy is cap and dividend. (SUSHABITAT)

> **Response:** As detailed in the Scoping Plan, the cap-and-trade program is designed to work in concert with a number of complementary measures, such as standards for cleaner vehicles, low-carbon fuels, renewable electricity, and energy efficiency. We evaluated four alternatives, including additional source-specific regulations, and found that none were as more effective than the implementation of a cap-and-trade program in carrying out the goals of AB 32. Staff has designed the program, including the cap, to be sufficiently stringent to spur GHG reductions to achieve AB 32 goals. We will closely monitor whether, over time, the cap-and-trade program is meeting the objectives set forth in AB 32. The premise that pollution trading programs do not significantly reduce air pollution is contradicted by experiences in other programs. The RECLAIM program in the South Coast Air Quality Management District has achieved reductions well beyond original expectations and continues to show increased reductions, including in areas adversely impacted by pollution and consistent with the ozone State Implementation Plan (SIP) for the South Coast Air Basin. As noted, the federal Acid Rain program has also gone well beyond original emission reduction estimates and has lowered control costs over what would otherwise have occurred under a command-and-control system. In both cases,

as in other market-based regulatory systems, adjustments have been made as problems are identified, and cost-effective emission reductions continue to occur.

O-6. (multiple comments)
Comment: The legislators in Sacramento who vote for bills like these are only greasing their own pockets in one way or another. When are they going to start voting for what is BEST FOR CALIFORNIA instead of their own self interests. This is a great example of why the Tea Parties are alive and still growing. They help the silent majority keep score on the voting records of these carpet baggers so we all can be more informed for the next election cycle. How can California implement laws that we cannot afford and expect the rest of the country to bail us out? (GIFFORD)

Comment: Stop messing with America's private enterprise system. If you choose to cap and trade your own business, be my guest, but no more treading on my children's attempts to take care of their own families. (NIELSEN)

Comment: We the people will not turn a blind eye to those in power who are making our problems worse, not better with the hearings on cap and trade. (SNOWDENT)

> **Response:** Climate change is one of the most serious environmental threats facing the world today, and California is already feeling its effects. In 2006, the Legislature passed and the Governor signed AB 32, which set the 2020 greenhouse gas emissions goal into law. AB 32 directed ARB to prepare a scoping plan outlining the State's strategy to achieve the GHG reduction limit established in the law. The Scoping Plan describes a comprehensive approach that includes direct regulations and a cap-and-trade regulation. The flexibility of the cap-and-trade program, together with specific design features included in the regulation to help contain costs, ensures that the reductions needed to meet the requirements of the regulation are cost-effective. Additionally, the cap-and-trade program is expected to drive investment in cleaner and more-efficient technologies to power California's economy. Information on the economic analysis can be found in Chapter VIII of the Staff Report and Appendix N.

O-7. (multiple comments)
Comment: The trade portion of Cap and Trade is a scam. (GOFF)

Comment: There is not a consensus in the scientific community that global warming is caused by man-made carbon. If carbon 'pollution' must be regulated, why not just regulate it? Adding the 'trade' aspect ultimately just means that money will be leaving the business's hands and ending up in government hands. It also means that industries will continue to pollute, just pay for the right to do so. This seems to suggest that the real goal might be just another government income source and /or more government control over the private sector. (PEABODY)

> **Response:** The allocation system is designed to reward those who have taken early action and have invested in energy efficiency and GHG emissions

reductions and will encourage continued investment in efficiency and clean energy in the future. Because the allowances can be traded, the program provides incentives for those with the most cost-effective reduction opportunities to reduce emissions quickly, and allows the market to find the most cost-effective overall reductions.

O-8. (multiple comments)
Comment: Keep exploring and implementing wind and solar energy. Please keep investing in these clean power technologies, and divesting from all the rest. Thank you, no biomass ever. (PHILLIPSS)

Comment: Consistent with prior CCC recommendations (see www.caclimate.org), the Board should establish an Executive Office level position with the primary responsibility of ensuring that the very clean technology and facility investments anticipated by the AB 32 program and its complementary measures (e.g., the low carbon fuel standard, the renewable electricity standard and motor vehicle technologies, among other measures) are expedited by ARB and its sister departments, commissions, agencies and air districts. (CCC)

Comment: It is important to put limits on carbon pollution that will be reduced to lower allowable limits over time, so that everyone investing in new technology will know that their investments will pay off over time. (RIEVE)

Comment: The future of energy use needs to be moving away from CO_2 producing sources. Solar energy cost is simply the cost of harvesting it. The process of building the solar industry will provide jobs that will promote spending money here instead of being shipped overseas, thereby boosting the tax base. Demanding that greenhouse gases be removed from the energy economy will provide the incentive for that industry to invest and grow, which will further reduce the cost. Legislation to require power companies to pay the prevailing rate to the small producer (such as home rooftops) will provide further incentive to commit the capital to put those solar panels into service. Additionally, local electrical generation eliminates the huge loss of energy that come with transporting electricity from central, distant power generating plants. This is a win-win situation for our state and country (except for big oil companies). This strategy will make worries about reducing greenhouse gases a moot point. (WOLF)

Comment: The fossil fuel companies need to get on board and be part of the solution and become innovative in creating clean energy technology. They have a heavy investment in fossil fuel energy so let's be empathetic and give incentives for the changes we want to see. Please support all legislation to move us rapidly in a new direction. (KRAY)

Comment: Californians want to lead the country in clean energy just like we did in the computer industry. By dedicating more of our desert lands to solar and wind development, we could be net energy exporters and create a major business and employment stimulus for our state. (YOUNGJ)

Comment: We need to develop clean energy. Give more incentives to home owners to use solar, double pane windows, and buy electric or hybrid cars. Please strengthen California's commitment to clean air. (DANIELSL)

Comment: I feel it is essential for California to take a leadership role in the development on clean energy. I believe the proposed program is a very good start even though it could hold big polluters more responsible for their emissions. I would like to see a more forceful program to get us on the right track. I should mention that as a father of a 5 year old boy with asthma I also have a personal investment in this subject matter. (MARTINR)

Comment: We need to reduce carbon based fuel, increase clean alternative energy without pandering to the polluters. (NAUSBAUM)

> **Response:** As detailed in the Scoping Plan, the cap-and-trade program is designed to work in concert with and enhance a number of direct measures that call for cleaner technology, such as standards for cleaner vehicles, low-carbon fuels, renewable electricity, and energy efficiency. For example, the bulk of electricity used in California is provided by publicly and privately owned utilities. These utilities are required by the Renewable Portfolio Standard to procure 33 percent of their electricity from renewable sources by 2020. In addition, State energy and environmental agencies are joining forces with the California Independent System Operator Corporation to expand cooperation as they advance carbon-cutting innovation and green job creation. California's Clean Energy Future points the way toward new investments in transmission, energy efficiency, smart grid applications, and increased use of renewable resources. Additional information on California's Clean Energy Future can be found at www.cacleanenergyfuture.org. In addition, Board Resolution 10-42 directs the Executive Officer to work with the California Public Utilities commission and publicly owned utilities to ensure that the proposed allowance value could include investment in energy-efficiency programs and renewable energy projects that achieve environmental and public health benefits. The regulation also includes a floor price for carbon, starting at $10 per ton, so that a consistent price signal is sent to clean technology developers.

O-9. (multiple comments)

Comment: I ask that the CARB not implement AB 32. California will be greatly harmed economically by so doing. California will push even more business and jobs out of the state. (FERNWOOD)

Comment: As a voter, taxpayer, and citizen of the State of California, I am concerned for the direction our state is headed. One hundred forty-four companies are leaving California for states that are more business friendly. Not the least of their reasons is the onerous regulations put in place in the name of protecting the environment. These regulations have been put into effect, with little science and a lot of propaganda. (RICKER)

Comment: The State of California and the California Air Resources Board has chosen to regulate the destruction of thousands of businesses. (STEVENSON)

> **Response**: We do not believe implementation of the cap-and-trade program will lead to the destruction of thousands of businesses. In developing the proposal, we conducted a comprehensive analysis of the impacts of the proposed cap-and-trade program on California businesses and business competitiveness. This analysis is described in detail in Chapter VIII of the Staff Report. The analysis showed that the proposed cap-and-trade program will not have a significant statewide adverse economic impact directly affecting businesses, and little or no impact on the ability of California businesses to compete with businesses in other states. In part, this is because the regulation includes methods to reduce competitiveness loss though the allocation process, such as through output-based updated free allocation, reducing the potential for competitive losses to California business.

O-10. (multiple comments)

Comment: To control CO_2 in our atmosphere, (I use this to mean all layers of the atmosphere in general) we would be better served to focus on reducing consumption of goods, planting trees and reducing actual production of CO_2, not pretending to do so by trading carbon credits. (KENNERLY)

Comment: The focus of CARB and businesses in the state needs to be on making our businesses more efficient and less polluting. Our manufacturing sector is one of the most efficient in the world. It makes more sense to reduce greenhouse gases by producing goods and services in the most efficient facilities here in the USA instead of having them produced in primitive inefficient plants in developing countries. The greenhouse gases are a global phenomenon. We need to focus on reducing man made greenhouse gases in other ways than cap and trade if we want to reduce global greenhouse gas emissions. (JEPSON)

> **Response:** While we recognize that these ideas are important to reduce GHG emissions, we considered other alternatives, and it was determined that a comprehensive plan with both direct regulations and a cap-and-trade program was the most cost-effective way to meet the goal of reducing GHG emissions to 1990 levels by the year 2020, and ultimately achieving an 80 percent reduction from 1990 levels by 2050. Alternatives that we considered to cap-and-trade can be found in Chapter IV of the Staff Report. The GHG reductions required under AB 32 cannot be realized without the active participation of the people of California. Therefore, individual behavior, such as reducing consumption of goods, will also play a major part in this important endeavor.

O-11. (multiple comments)
Comment: Consider implementing a carbon tax. (SUCKOW)

Comment: One aspect of the proposed regulations that goes the wrong way is the "cap and trade" provision. We don't need to turn the current pollution levels into an asset which can be traded. This would have the effect of ensuring that the pollution "cap" is exploited to the maximum extent. It's better to implement a carbon tax, even if it's minimal at first, which adds to the cost of carbon pollution, and thereby creates a consistent, across-the-board incentive to reduce greenhouse gas emissions. (ZIMMERMANM)

> **Response**: We considered alternatives to the cap-and-trade program and implementing a carbon fee was one of the alternatives considered; however, we determined that a cap-and-trade program was more favorable. Details on why we chose cap-and-trade over a carbon fee can be found in Chapter IV of the Staff Report.

O-12. Comment: I can get into what I know about CARB and I can tell you what I do know I don't like at all. But the real thing that I don't like is that this thing is over 3,000 pages and I can't even begin to understand it. This is not clever we do know why you make these things so big and confusing. It is so you can make it do anything you want it to. This is bad legislation and it was done by unelected people who have no right to set laws regulations taxes or fines. (NCTPP1)

> **Response:** AB 32, which was enacted in 2006, sets the 2020 greenhouse gas emission reduction goal into law. The AB 32 Scoping Plan identifies a cap-and-trade program as one of the strategies California will employ to reduce the GHG emissions that cause climate change. The proposed cap-and-trade regulation and the Staff Report were released concurrently for public review. The Staff Report contains detailed analyses of the requirements in the proposed regulation. The analyses include the environmental impacts, economic impacts, and technical evaluations and are presented, along with supporting documentation, in several appendices to the Staff Report. Although the report is a large document, a summary of the details of the cap-and-trade program was included in the Executive Summary and Chapter II.

O-13. Comment: Even Al Gore admits ethanol is a mistake. It increases government costs through subsidies. It increases costs to all consumers for fuel. It does nothing for the environment. It uses more energy than it provides. (FAULKNER)

> **Response:** The low carbon fuel standard considers full lifecycle impacts of fuels, including ethanol as an approved pathway to comply with the regulation. Cap-and-trade has a compliance obligation for transportation fuels and fuel suppliers that helps to drive the long-term transition to cleaner fuels well into the future. Cap-and-trade creates a price signal on fuels to drive long-term

investment in cleaner fuels, encourage energy efficiency, and to do so in the most cost-effective manner. We believe that the price signal would provide an incentive for investment in clean fuels. Additionally, including fuels in the program provides a consistent price on GHG pollution throughout the economy and ensures a level playing field across all fuels and consumers.

California Can Not Stand Alone/Insignificant Impact

O-14. (multiple comments)
Comment: Please do not take any more steps to reduce emissions in California without agreement at the national level that every state and the District of Columbia will agree to these new standards (a national policy better developed by the EPA and DOE); and new standards that are International in scope with China, India, Russia, Brazil, Indonesia, and the European Union. Without such agreement there is little to no incentive for California's taxpayers, ratepayers, and businesses to support a unilateral tax on emissions. (ENP)

Comment: We have too many people on the planet to support, and one state trying to control what does or doesn't go into the air is utterly ridiculous when other countries and continents so blatantly pollute. We have small farmers businesses in California that have tried to survive without getting enough water because of a non-native FISH! Their livelihoods are destined to crumble now if they have to comply with all the new regulations, while big corporations can buy carbon shares to offset their emissions? I want my food locally grown, not shipped from somewhere else in ships or planes that pollute way more than a local organic farm!! Get real, people. It's the rest of the world that needs educating - Regulating California alone is NOT going to make a bit of difference. (MAYNE)

Comment: Cutting 100 percent of the world's CO_2 emissions lowers CO_2 emissions by a whopping 1.5 percent of the carbon cycle. The remaining 210 billion metric tons per year (Source: J Christy, 2002) comes from natural processes. So, how much of an effect would cutting 100 percent of California's emissions have? Less than 0.15 percent. This is bad economics and bad policy. It's not about saving the world (except for the true believers) it's about money. Follow the incentives. Baptists and bootleggers, true believers and the buck-seekers, have banded together to make markets out of thin air with offsets or allowances. (BENSON)

Comment: There is no question that we are having a global climate change occur. The causitive agents have been incorrectly identified as manmade greenhouse gases. From current articles and publications, it appears that only 5.5 percent of the global greenhouse gases generated are manmade. California emits 1.2 percent of the manmade greenhouse gases. The reality is that passing a Cap and Trade program in California will not have any measurable effect on the global greenhouse gas emissions. (JEPSON)

Comment: On the national and international front, California leadership is a source of humor. It's really not taken that seriously anymore. We're very unique economically and the way we're handling ourselves. If a state can create a market for a product and a service that a private individual would never create and be successful in that and lift the overall quality of life and improvement for its citizens, I'd love to see it. It's never been done. I challenge you to work out some of these details that we've been talking about and do it. Internationally, Kyoto and Copenhagen failed. Most recently, Cancun resulted in how you redistribute capital, not in about CO_2 emissions. And I think that's where the argument has come from. The U.S. Senate would not deal with it. Our Legislature is killing the EPA committee for next year. (FORD)

> **Response:** While we recognize we cannot do it alone, California's economy is among the top 10 largest economies in the world, and is therefore is uniquely positioned to take action. Our climate change plan relies on a strong network of climate partnerships. California is working with other states, jurisdictions in the WCI, and the federal government to encourage the reduction of GHGs. Climate change will adversely affect public health, the environment, and the economy in California. California has a long history of leadership in protecting public health and the environment. For example, California's GHG standards for cars have been adopted by the federal government. Adoption of the cap-and-trade program is the next step in that leadership.

AB 32

O-15. (multiple comments)
Comment: We cannot afford more unnecessary debt especially when it would take food off the plate for many. That equals a big no and asking to suspend AB 32. (CVTP)

Comment: AB 32 must have been cooked up by a team of people with purely evil intentions. To think that this is perfectly fine to implement is hard to comprehend. (GIANNINI)

Comment: Please don't go ahead with AB 32 at this time or at any other. That is the wrong thing for California at this time and will have no effect or an unmeasurable effect on climate but huge negative effect on employment and the economy. (GOEDJEN)

Comment: American workers cannot afford this nor are most even interested. No AB 32. (SNOWDENB)

Comment: Suspend AB 32 until the unemployment in CA is 4.5 percent for four straight quarters. Those who can least afford the increase in electric rates, gas prices will be affected. (DECKER)

Comment: With the sad state of affairs in California, the last thing this state needs is more regulation. We've already driven record numbers of businesses out of the state. I am opposed to the implementation of new regulations that will come with AB 32. (BONASERA)

Comment: This is the third recession I have experienced and yes, we have always pulled through them. California? I'm not so certain, because there is something here that was never here after the last recessions, CARB and AB 32. We had 150 employees in 2007 and we now have 12. (PARIGORIS)

Comment: Suspend AB 32 until unemployment is below 5.5 percent. (MUELLERS)

Comment: I'm writing to urge repeal or, at least, suspension of AB 32. With the staggering number of people out of work and businesses fleeing California, this legislation is absolutely the worst thing that can happen to us. I live in San Joaquin county and the number of foreclosed homes and empty buildings where long standing businesses use to be is frightening. Please help us. Use some common sense and stop this. We Californians cannot afford this. (ALLENKIM)

Comment: The hard working souls of America are already struggling to survive in this economy. No on AB 32. If this continues there will be even more people on the streets, more people in debt, more people collecting un-employment, and more people not owning businesses. This means less revenue from the people, which in turn means America in debt (even more than America already is in debt) Get the idea. No on AB 32. It is no longer about "global worming" anymore! I have heard some whoppers in my time but that one tops them all. (CARRILLO)

> **Response:** Climate change is one of the most serious environmental threats facing the world today, and California is already feeling its effects. In 2006, the Legislature passed and the Governor signed AB 32, which set the 2020 GHG emissions goal into law. AB 32 directed ARB to prepare a scoping plan outlining the State's strategy to achieve the GHG reduction limit established in the law. The Scoping Plan describes a comprehensive approach that includes direct regulations and a cap-and-trade regulation. The flexibility of the cap-and-trade program, together with specific design features included in the regulation to help contain costs, ensures that the reductions needed to meet the requirements of the regulation are cost-effective. Additionally, the cap-and-trade program is expected to drive investment in cleaner and more-efficient technologies to power California's economy. Information on the economic analysis can be found in Chapter VIII of the Staff Report and Appendix N.

Make Polluters Accountable

O-16. (multiple comments)
Comment: Please do not allow large polluters to pay a small fee and continue to pollute California. If they must be given a break, then make the fees high enough to solve California's budget crisis. (MARKS)

Comment: Please clean up the cap and trade scheme so that businesses below the cap don't trade credits with other polluters who have not cut emissions. California used to be on the cutting edge of forward thinking. Set the standards for a better future and for the rest of the country to follow. You have the opportunity to write a cleaner future for the entire country. (SUMMER)

Comment: I want a plan to reduce GHGs that does not allow big polluters to further profit from their pollution. Please no credits to pollute. (LAROSE)

Comment: I am concerned that corporations or other entities that will continue to pollute are not held accountable for the destruction that they create and I want to support the board in establishing stronger standards of consequence for continued polluters. (YESSNE)

Comments: I agree with tighter restrictions on greenhouse gas emissions. We need to stop turning a blind eye to pollution just because the polluting company has political connections. In my opinion that's the biggest problem. Companies should be forced to stop polluting, not just buy politicians. (CUNNINGHAM)

Comment: For too long, big polluters have been leaving their giant footprint on our state. The deceptive Proposition 23, funded by Texas Oil Companies, to suspend AB 32 was defeated by 61 to 39 percent. Seeing such results, this must bring an important message. It says that we've had it with polluters, and we will not tolerate their filthy actions anymore. (VALDEZ)

Comment: The data is there so please act accordingly and strengthen the proposed program for decreasing global warming emissions from the state's largest polluters. (BOGIOS)

Comment: Thank you for your work on greenhouse gasses. Please correct the one portion of the bill that would allow the worst offenders to continue polluting. (PAHRE)

Comment: Please don't allow the biggest polluters to pollute more; there must be a better way to implement this plan! (STEINMANA)

Comment: The use of scientific data should inform our discussions on the environment. One would think that with continuing advancements in data collection, and research methodology that the information coming from research would be granted more and more credibility, but it seems that is not the case. Moneyed interests speak louder than scientists and a logically thinking and informed citizenry! Please stand up for your citizenry and the scientific community and remember that the voices of industries that pollute should not overwhelm the voices of us who have to live like "canaries in a coal mine." (POTTER)

Comment: The people of California have voted and defeated Proposition 23. Why are oil companies trying to circumvent the peoples' decision? Why are you even considering going against the will of the voters? Oil and gas pollute our lives, our lungs and apparently our legal system. Please don't tell us that this is about jobs, because really, it is about our health, which is a wonderful thing and often taken for granted until people lose it. You have an obligation to the people of this state, and even more, you have an obligation to the planet. To bend to the will of the oil companies is to send us all hacking, coughing and dying. (CASEY)

Comment: There is no need for a cap and trade system that, even by our best estimates will have a negligible effect on our local and global climate. This will be a waste of huge sums of money that will not curb CO_2 pollution from large "polluters" because they can purchase credits from those who create less CO_2. This is a complete wash in terms of CO_2 production and only serves to transfer money from one business, filter it through brokers who will take their share and then give it to other industries who are already conducting business with little CO_2 production. (KENNERLY)

> **Response**: We have designed the cap-and-trade program to be sufficiently stringent to reduce GHG emissions to achieve AB 32 goals. Covered entities will be subject to an enforceable and declining emissions cap, spurring the installation of more-efficient and lower-emitting technologies. They must turn in allowances or a limited number of offsets to match their GHG emissions. Allowances will be largely distributed for free in the early years of the program, transitioning to a program in which most allowances are auctioned. Because there is a decreasing cap on emissions, overall emissions will go down. Allowance trading is an important cost-containment mechanism. The price of allowances will be determined by the cost of available emission controls. Our analysis indicates that the cap-and-trade regulation is expected to have a beneficial impact on air emissions by reducing emissions of criteria pollutants and toxics, including those from larger industrial sources. Based on available data, current law, and policies that control industrial sources of air pollution, and expected compliance responses, we believe that emissions increases due to the regulation at the statewide, regional, or local level are extremely unlikely, at best. Nevertheless, the Board is committed to monitoring the implementation of the cap-and-trade regulation to identify any situations where the cap-and-trade program has led to an increase in criteria pollutant or toxic emissions.

Climate Change is Real

O-17. (multiple comments)
Comment: There is by now sufficient scientific information on greenhouse gas emissions to warrant their close study and control. Those who oppose this either have a financial stake they don't want to relinquish or they are too dumb to even recognize the emissions problem. (WHITER)

Comment: Ninety eight percent of climate scientists believe that climate change is real and that it is caused largely by human action. It's time for action to reduce greenhouse gasses. (BOREAN)

Comment: While debate is healthy, conspiracy theorizing is not. The vast majority of climate scientists do not hide out and make their findings up. They measure the large scale changes happening around the globe, including unprecedented amounts of warming gases in the atmosphere. Religion and ideology should not be a part of policy making. I urge you to regard the science and the public good as top priorities. The true costs of business and pollution must be calculated and figured in to prices and the costs of doing business. I applaud your efforts in these areas. (LERNER)

Comment: The climate science is clear, as are the increasingly devastating effects of climate change on populations all over the globe, we must act now. Statewide emissions caps are a small, small start. But we have to start now. It is almost too late. (KOIVISTO)

Comment: There are no legitimate scientists who dispute that increased levels are a result of human activity. CO_2 in the atmosphere continues to increase unabated. It has reached unprecedented levels. The earth's average temperature is rising. Cooler in some places, but overall, it is warming. Sea ice is melting at ever increasing rates and oceans levels are already rising. This information is not opinion, but scientific fact and recognized as such by NOAA and other internationally recognized institutions and governments. We must come together and place limits on CO_2 production. Create the limits as caps, dividends, rebates, or other incentives in the big picture. The means are less important than the goal. Put a stop to the naysayers, doubters, time-wasters, and politicians who don't care to understand the science. Cap greenhouse gases now please. (WOLPERT)

Comment: Can we stop having rhetoric determine public policy and use science as a basis for our decisions? Global warming is real and we need to do what we can to cap it. (MATHEWS)

Comment: I feel it is imperative that we reduce greenhouse gas emissions. What more do we need to know we already have global warming and that time is running out? We already have the seas rising, North and South Poles melting, and the life in our seas dying. Please do what is needed to stop global warming. (CRUMP)

Comment: Our economy cannot afford to allow anyone to continue spewing greenhouse gases into the air. Consider what is going to happen as climate change worsens; the central valley becomes drier, sea levels rise, storms worsen and cause more property damage. As air pollution worsens, more health costs will incur. Rates of asthma will increase, and more of us with breathing problems will be hospitalized. State costs for alleviating the problems will be much higher than the costs of preventing them. (FRONCE)

Comment: As a California college science educator I urge you to take all legal actions at your disposal to expedite the control and reduction of greenhouse gas emissions in California. Global warming caused by human activity is now beyond dispute among the honest voices in the scientific community. Responding to mediate its possible consequences is prudent public policy that will increase quality of life and create incentives for badly needed economic innovation. (RICHARDSON)

Comment: It is clear to me that climate change is real, not a hoax. In the name of all of our children, give science priority in your deliberations. (BOWLES)

Comment: Any educated individual who continues to deny global warming is an ignoramus, and, I suggest, to be considered a criminal for committing an act of violence on people and property in refusing to join the effort to contain this catastrophic planetary event. (KELLEY)

Comment: As a working scientific researcher, let me assure you that there are very few scientific conclusions that are more certain than the evidence for climate change, and that the evidence just in this year indicates that the situation is even worse than we thought when AB 32 was passed. The agricultural damage and human suffering we will see from disruption of our delicate water system in the Delta and the Central Valley is important around here, not to mention the damage to the coasts from rising sea levels in our children's lifetime. (AMENTA)

Comment: Climate change is happening. Action now is needed to slow it and ameliorate its effects. Otherwise humanity is committing suicide. (KUTCHER)

Comment: Please think of the future of our planet which is greatly endangered by global warming. We have a duty to future generations to begin now by enacting AB 32 to provide a reduction in carbon dioxide by 2020. My grandchildren are counting on you to do the right thing. (LENERT)

Comment: The conservative media, and yes it is conservative and not liberal and its conservative owners propaganda would have you believe, maintains that climate change is not a thing to be concerned about. I wonder why they would say such a thing. Is it because they always put the profits of business before the well-being of people? I will believe the word of the Union of Concerned Scientists that say climate change is a problem because I know that they put truth before profit and propaganda. The media that is for the most part owned by wealthy conservatives will always put profit first. Therefore, if you have a lick of good sense, you will also listen to the truth tellers, the members of the Union of Concerned Scientists. (YOUNGL)

Comment: Warming is just one consequence of human activity, be it from burps of cattle, cars or burning forests by the acres per minute. Warming is one of many negative consequences from melting ices which raise the ocean levels, fluorocarbons which depletes ozone which increases solar heating. Other more remarkable effects of human activities include wasting of oceans which destroys the carbon retaining qualities of sea life; overfishing which changes the eco-balance to favor ozone depleting species; economic subsidies to industries exploiting energy sources with both huge carbon footprints and enormous polluting, health and environmental costs as are the cases with coal, oil, 'nuclear' and 'natural gas'. All these confluences impact the earth in a highly negative fashion independent of their specific 'warming' effects. It is not a case of just one or two million people polluting and laying waste, but an issue of two billion people doing this and another three billion aspiring to do this. (BURCH)

Response: No response necessary.

Based on False Science

O-18. (multiple comments)
Comment: Your current designs to force cap and trade on the people of California is misguided and disastrous. This is bad policy based on flawed and fraudulent science. (WIECK)

Comment: Please reconsider your stance on cap and trade. Much of the so called science is being shown to be bogus. There is no "global warming"; it is total fakery, read your history books. (KELLOGG)

Comment: Man caused climate change is myth. The cap and trade scheme is a power grab, pure and simple. (HUTCHINGS)

Comment: NASA has updated their climate change models to show that an increase in CO_2 will induce a corresponding increase in oxygen which will reduce the predicted increase in temperatures in their prior models by half. This decrease in predicted temperature would meet the goals of the most ambitious EPA and CA regs on reducing CO_2 and its predicted impact on reducing the earth's temperature. Bottom line, whatever the regs are the earth has already made the necessary adjustments to reduce the temps making the regs unnecessary and counterproductive when it comes to California's economy. (LANDOWSKI)

Comment: Cap and trade/global warming/carbon emissions (CO_2) is a huge fraud that will make route California and the country. They're been 16 straight years of global cooling. (LARIMER)

Comment: We do NOT have global warming; we have global climate change. Climate change has existed ever since the earth was formed; AND there is no irrefutable evidence that climate change is caused by human activity. (MANGAI)

Comment: This whole human caused global warming thing has been thoroughly discredited. If you pass this bill you will be seen as hurting the economy in the name of a hoax, that you are not up to date on the research. Be bold and do the right thing and vote NO! (KEEFER)

Comment: Don't do this. It is based on bad science and will hurt companies and individuals already failing from the economy. (DENNIS)

Comment: It's well known that a lot of the "science" regarding, global warming, gas emissions, pollution is specious and if what is being discussed and carried out without Californians being able to vote on it. (TITUS)

Comment: The science is flawed. (LYNES)

Comment: This false science and bunk has no place in the real world. Do not even waste time discussing this political farce and false science. (WITT)

Comment: Global warming is a hoax. (ROLLS)

Comment: Why would you people promote regulations based on false science? I can only surmise that your political agenda overrides and demonstrates the miniscule respect you have for the people of our great country. Shame on you. You should and need to be replaced for the benefit of our prosperity. This type of policy is indicative of just how much you hate America. (BELLOVICH)

Comment: Have you not heard of Climategate, which became known a year ago this month? The scientists on climate have been cooking the books for years. There is no such thing as global warming. The climate of this planet changes constantly, it's nature. It is arrogant to believe that man can change the climate of this great planet. (YOUNGHARLAN)

Comment: I have a big quarrel with making political and business decisions for the state and country based on a scientific lie. The greenhouse theory has been shattered by scientific analyses and is simply invalid. In December 2008, 650 plus climate scientists from all corners of the globe made their concerns about global warming alarmism known on the U.S. Senate floor. In a March 30th, 2009, New York Times ad, 115 climate researchers, scientists, and others essentially called President Obama a liar for his comments about anthropogenic global warming. It is astonishing to me how organizations such as yours and willing accomplices in the news media continue to talk and proceed as if 99 percent of climatologists agree with you about anthropogenic global warming, when surely the majority worldwide sharply disagree with you. I'm sure your actions are well meant, but they are misguided. My question to the EPA and CARB is, when do you stop lying to the American people? (MOORHEAD)

Comment: In September 2006, AB 32, aimed at reducing greenhouse gas emissions was approved. This stems from a contention of the Intergovernmental Panel on Climate Change that global warming results mainly from burning fossil fuels, pumping carbon dioxide into the atmosphere. However, 31,487 scientists, including me, a Geological Engineer for half a century, petitioned the government to reject that contention, recognizing it as a hoax. (SULLIVAN)

Comment: I just question the goals of AB 32 personally. I don't believe that the goals are based upon scientific fact. They're based on consensus. Consensus historically — the quote I have is "Consensus has been the first refuge of scoundrels. It's a way to avoid debate by claiming the matter is already settled and closed." And I don't believe that's true. A whole lot of scientific evidence is out there. In fact, we see monthly, weekly, if not daily things, findings, whether it's from NASA or other organizations, former IPCT members, et cetera, that are questioning the current consensus. (HASSEBROCK1, HASSEBROCK2)

Comment: We respectfully ask that you vote to suspend AB 32, now. California does not need this legislation, especially now during this very bad fiscal time for the state. The research has been based on false information, stop it now. (TOZZINI)

Comment: Please suspend AB 32. There is no global warming and this will wreck our state. Other states have reconsidered and stopped. California should do likewise. (MUELLERD)

Comment: I see no need for this harmful legislation. I have read enough to understand that the science behind greenhouse gas and carbon emissions is faulty at best and phony at worst. The science is not there for you to consider this harmful protocol. Take this off the table. (EASTMAN)

Comment: AB 32 is very bad bill based on fraudulent science. (WELLSWILL)

Comment: Has anybody in the Air Resources Board even bothered to hear the opponents arguing against the climate change theory? I respectfully ask all of the Board to slow down and start looking both sides of the aisle before making any reserved ideas. (GUERRERO)

Comment: The earth has over the ages experienced many dramatic weather events, all of which are not the result of any man made factors. Classes in astrology have also mentioned that the planetary alignment has and will continue to change this earth as well as the seasons. Please delay any new regulations until full and accurate studies have been concluded. (RODOWICZ)

Comment: I'm really asking why we are doing this. Four years ago, I think when AB 32 came on the scene, there was a lot of emotion, a lot of interest, you know, and science kicking around that justified it. Today, about 30,000 scientists say it doesn't make sense. If you look at the carbon issue itself, carbon dioxide averages 6 percent of the greenhouse effect. If you multiply that by 3.4 percent of that emitted to the atmosphere annually that humans can claim responsibility for, then a whopping 0.2856 percent of global warming is human related. So I'm not sure I know why we're doing this. (FORD)

Comment: NASA earth science has just come out with a paper that indicates that the earth is moving into a new ice age and that man-made CO_2 is the only thing that can slow down the coming ice age. This means we need more CO_2 not less if we are to prevent the destructive forces of a new ice age which would blanket the earth in glaciers which is very bad for the future of the human race. Given this new data from NASA

PLEASE stop all your efforts to reduce CO_2 as CO_2 is the only thing that can keep the planet green and free the earth of ice. (BRYANT)

Comment: Of every one hundred scientists who have studied climate change, does the majority agree it's a real threat or just a hoax? Will people who claim global warming is a real threat have a direct financial interest in the fight or the deniers, who believe global warming is a hoax, have more at stake? (BUI)

Comment: With so much false information out there on global warming and climate change, I believe that now is not the time to impose regulations that cannot be proven to prevent any adverse climate conditions. (RODOWICZ)

Comment: Please do not over-reach the science in promoting "cap and trade." As has been shown in the past year, the proposition is founded on "shaky" science, which is by no means agreed upon by all. Until that science has "caught up" and been verified, please do not politicize or monetize or penalize it. (BROWNT)

Comment: You choose to ignore the hundreds of scientists who have come forward showing evidence that there is no such thing as “man-made global warming.” You also continue to ignore the fact that your draconian regulations are driving more and more businesses out of the State of California. (PINKSTON1)

Comment: AB 32, although well-intentioned, creates a solution for a non-existent problem. The theory of anthropogenic global warming is founded on studies and reports that, in recent years, have been confirmed to be inaccurate, misleading, and even fraudulent. I believe that there is enough reasonable doubt regarding climate change to postpone the implementation of the AB 32 mandates, at least until more conclusive science is presented. Even if global warming was supported by science, your own staff report states that California alone could not prevent it. The AB 32 policies will not produce a significant effect towards combating climate change; instead, a great majority of the world's nations would also have to create, implement, and adhere to strict cap-and-trade programs. The chances of this coalition forming are unlikely, so as California undertakes the solitary mission of cooling the earth, we merely put ourselves at a severe economic disadvantage. (LAMALFA)

Comment: Global warming is a pathetic hoax. According to the Heritage Foundation's National Center of Policy Analysis, greenhouse gases make up only two percent of the earth's atmosphere and carbon dioxide is only 3.62 percent of all greenhouse gases. In addition to that, all human activity creates are infinitesimally small .0025 percent of all the carbon dioxide in the atmosphere. So mankind's contribution to the non-existent problem is miniscule. Add to that the fact that the maximum reduction of man-caused carbon dioxide via the implementation of a global cap and trade program is estimated to be less than three percent, and simple logic tells us that even if global warming were an authentic threat, our very best efforts would have no noticeable impact. (MYERSG1)

Comment: Considering human caused global warming is based on junk science "climate gate." There is little to no reliable evidence that carbon dioxide has any warming effect on the planet. In fact carbon dioxide is an essential element in our atmosphere. (JENKINS)

Comment: The empirical data doesn't support the theoretical assertions that CO_2 is causing climate change. To live healthy and productively, carbon dioxide is an essential building block that is needed. Using the current levels of CO_2 of 380 parts per million (ppm) in the air, you realize that carbon dioxide is hardly at a level of concern. The threshold limit value (TLV) for human toxicity is 5000 ppm according to OSHA standards. This tells us that our health is not in jeopardy, yet still the proponents of global warming insist we are in an ecological crisis. None of this makes anecdotal or empirical sense and tells that we should not allow ourselves to be lied to and made to pay for changes in our behavior or regulations to reduce the levels of CO_2. (GILDERSLEEVE2)

Comment: As a student of chemistry and natural history, as well as a business-owner involved in emissions testing, I suspect that the true agenda behind such greenhouse cap and trades is not based in science but rather emotional nonsense that will benefit those staged to reap on the trade of a "new type of trade" element. Carbon dioxide is not and never will be a bad gas. It is an essential component of life on earth. I do support reduction of pollution but CO_2 is the wrong route. (BAPATRIOTS)

Comment: This is a tax imposed by a group instead of congress and thus, it is illegal. We have too many taxes as it is. The president is finding a way to get more money out of us citizens thru the EPA. It is based on lack of science and a hypothesis without being proven. It is unintelligent and unnecessary. There is not enough proof to be able to do this taxation without representation. (SCHRANK)

Comment: The environmental warming caused by humans is a hoax founded by Al Gore who has no training or expertise in this area. His expertise is to get much money from this hoax. The global warming scare is based on biased and dishonest use of weather data from around the world. (DURKEE)

Comment: It is apparent to anyone with their head above ground and their eyes open that global warming is a farce. Ask any geologist, the earth has been warming for 16,000 years. This is without the impact of humans. CARB is just another big scam being perpetrated against the people of California for the benefit of a few political lobbyists and their constituents for a pure profit motive. California's air is now better than it has been in many years. More regulation will only drive more businesses either out of business or out of State. We do not need either of these to happen if we are to survive as a State. (SMEDLY)

Comment: A recent Rasmussen poll says 59 percent of American people do not believe in man-made climate change. There is now a consensus of 1,000 scientists worldwide who now agree there is no such thing as global warming caused by man's activities on earth AND in fact, the earth is not warming. Today you start discussing the implementation of AB 32 based on bad science and a fabricated crisis created solely for the redistribution of wealth. The hockey stick graph used by global warming alarmists uses data that omits the med-evil warming period and used a limited sampling from centuries old tree rings. Any tree ring samples that conflict with the desired conclusion of global warming were omitted. The hockey stick is a hoax and the stick is broken. I now know the greenhouse gas that effects temperature is H2O not CO_2 and so does anyone who is an informed citizen. Please stop living the lie. Let AB 32 die. (PORTERJ)

Comment: Even the "global warming" folks essentially admitted that it was a lie and changed it to "climate change." Still, you guys seem not to have figured it out yet. Get rid of Cap and Trade or you will have to remember that you were the problem when California goes bankrupt. (HOLMES)

> **Response**: We have a widespread scientific consensus supported by national academies and all the major scientific institutions solidly behind the warning that the temperature is rising, *primarily as the result of human-caused greenhouse gases*, and that the warming will worsen unless we reduce emissions. The overwhelming majority of scientists are in agreement about the following fundamental conclusions: (1) the world has been warming and will continue to warm for the foreseeable future, (2) the warming is largely due to human activity (burning fossil fuel—oil, coal, and gas—and destroying forests), and (3) the consequences of rising temperature, in all projected futures, are grave enough to warrant global action. Our climate is changing in ways that are not caused by natural variability; human activities are responsible for most of this unusual change; significant harm to human well-being is already occurring as a result; and far larger—perhaps catastrophic—damages will ensue if serious remedial action is not started soon. You may view or download information detailing the facts on global warming and climate change on our website at www.arb.ca.gov/cc/facts/facts.htm.

Not Applicable

O-19. Comment: The California incentives for alternate energy has allowed Sierra Nevada Brewing in Chico to buy four fuel cells that run on the spent brew mash to generate 1 meg of power (surplus being sold), the heat from the cells "gooses" the new brew, they now have no disposal problem (which cost over $1 million a year) and a very low carbon foot print. (HAFER)

> **Response:** No response necessary.

O-20. (multiple comments)
Comment: I urged Sec. Chu to enforce the clean energy bill and to strengthen it wherever possible. Our children and grandchildren expect us to act as their responsible stewards. Many other states will emulate us. (AMES)

Comment: The electricity generated by all three plants at the Ivanpah Mojave Desert solar complex will be enough to serve more than 140,000 homes in California; more than 13.5 million tons of carbon dioxide emissions will be avoided over the 30-year life cycle of the plant. This solar complex also cuts major air pollutants by 85 percent compared to new natural gas-fired power plants. As a matter of national security regarding the survival of Americans and of the California Global Warming Solutions Act of 2006, ARB should solicit the assistance of the federal government to contract with the BrightSource Corporations and the BrightSource corporate investors to increase the number of Ivanpah projects by 150 times to eliminate carbon-based sources of electricity for the state of California, and to begin construction of these 150 solar complexes no later than 2013. (STARRY)

Response: No response necessary.

O-21. Comments: Most lifeforms survive better in an environment that does not contain substances harmful to that lifeform. Money does not change this Natural standard. Humans are such a lifeform. (ANDREWS)

Response: No response necessary.

O-22. (multiple comments)
Comment: I can't believe you would go through with this. Haven't you liberal politicians done enough to ruin this state already? There is no hope in sight when a bunch of liberals with no business experience control this state, along with the unions. (LAMPHERE)

Comment: Your messages during the elections about big oil were deceptive. I guess that’s the way of politics. (RAMSEY)

Response: No response necessary.

O-23. Comment: The board is not, unbiased, but partisan to the core. We need to see that board dissolved. We in the state of California need to come to our senses, no amount of taxation or carbon dioxide control will ever work to create a job! CARB destroys jobs, and destroys the tax base. (MARS)

Response: No response necessary.

O-24. Comment: It seems that all the things that have made California a great State have somehow become bad? How is it that so few can lay waste to so many that have worked so hard to grasp a little piece of the American Dream? Once they have destroyed our economy, they will wonder who will pick up the tab for their lavish life style, but unfortunately the old work horses that carried the load will be gone. (CORREIA)

Response: No response necessary.

O-25. Comment: You will kill 90 percent of the lawn care jobs. How will the illegals work then? They will hopefully go to Sacramento and demand Ms. Nichols for a check which she has taken from them. (NORDYKE)

Response: No response necessary.

P. OPPOSITION

This section includes responses to comments expressing opposition to the regulation. Major topics concern general opposition to the cap-and-trade regulation and AB 32, opposition to regulation in general, and the public process held during development of the cap-and-trade regulation.

Oppose Cap-and-Trade

P-1. Comment: We oppose the Board's adoption of the cap-and-trade rule and join the comments submitted by the Center on Race, Poverty & the Environment, the Center on Biological Diversity, and Communities for a Better Environment. (FORMLETTER11)

> **Response:** We acknowledge your comment. Please refer to responses directed to comments submitted by the Center on Race, Poverty & the Environment, the Center on Biological Diversity, and Communities for a Better Environment in Chapter III Summary of Comments Made During the 45-day Comment Period and Agency Responses, parts B, E, F, H, I, K, M and R.

P-2. (multiple comments)
Comment: Cap-and-trade should be called cap and tax because that is what it does. No more taxes, please. (CROOKS)

Comment: This is not what we Californians want. You do not have our better interests in mind and will continue the distain that the world holds California in. (MATTOX)

Comment: Please do not pass this bill. It would be highly difficult for our family and many others to pay more for gasoline. Plus, ethanol is a very inefficient use of fuel. It has cost farmers untold grief already. Please do not kill the monetary system in the State of California. We are holding on by a thread as it is. (DANIELSE)

Comment: It is not the time to be instituting new programs. Please do not adopt this cap-and-trade regulation. (SMITHR)

Comment: Eliminate this program and build new jobs for the Central Valley farmers and make California's agriculture business the best in the US. (GALLAGHER)

Comment: The proposed cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms Regulation, including compliance offset protocols has been proven to be unsubstantiated. I implore you to stop with these draconian regulations for the health of California. (GILDERSLEEVE1)

Comment: The cap-and-trade documents show that CARB continues to imagine that moving forward with this proposal will show leadership in the fight against supposed global warming. However, since California began to show leadership with the passage of AB 32 in 2007, every state but New Mexico has declared that it does not want to join us in a cap-and-trade market. Please remember that you represent the people of California, not just eco-left special interests. This proposal is divisive and endangers the livelihoods of many families while failing to inspire other states to follow. Please reconsider. (COEU1)

Comment: I would urge you to vote against this bill and/or the implementation of the provisions of this bill. This is the wrong time to implement legislation that will impede the progress of businesses in California. (HARRISONW)

Comment: Who determined that anyone has the right to tax, regulate, or anything the air which circulates everywhere, to everyone anyway? This tax is just another way for people to control everyone they consider to be lesser beings than themselves. (SMITHM)

Comment: This is wrong and we the people of this State know it and want it stopped at any cost and in any way we can. This will only speed up the decline of our great State and Nation. For your own good and every Californian's good, do not do this cap-and-trade deal. (NCTPP2)

Comment: I am opposed to the implementation of regulations to enforce AB 32. (FINE)

Comment: I am opposed to the adoption of this proposal. (WESTERND)

Comment: Just say no to cap-and-trade. (SCHAEFER)

Comment: Please do not adopt the proposed California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms Regulations. (SODERLING)

Comment: We do not support your cap and trade scheme. (NORRIS)

Comment: No cap-and-trade of carbon credits. Leave my energy use alone without surcharge. (CRANFIELD)

Comment: Do not institute a "cap-and-trade" policy for California. Polluters should be made to pay a tax for their excessive carbon emissions in this State, not be allowed to "trade" with a non-polluting company so that they can continue to foul our air and water. Pass a carbon tax with an allowable limit of pollution that is reduced on an annual basis. This will force polluters to actually clean up their act. (SMITHG)

Comment: It’s hard for me to believe that you are still attempting to destroy the State of California with these bogus and ridiculous regulations you are attempting to impose on us. It has to be stopped. (COYLE)

Comment: Cap-and-trade has nothing to do with the environment or global warming. It is a political charade designed to pay for a liberal agenda item. (CURTIS)

Comment: Absolutely no on California cap on greenhouse gas. (VANOOSTERHOUT)

Comment: I oppose any legislation that would impose a cap-and-trade policy for the State of California. (BILLIA)

Comment: I oppose this bill. No more government regulation. (HILLR)

Comment: The cap-and-trade idea is absolutely the wrong direction for California and the country. (MURRAY)

Comment: If the world's best scientists cannot produce overwhelming proof that a cap and trade system will ultimately have significant and demonstrable changes in our climate, then why would we even consider this system? (KENNERLY)

> **Response:** Climate change is one of the most serious environmental threats facing the world today. The California Global Warming Solutions Act of 2006, Assembly Bill 32 (AB 32), required us to adopt regulations which would implement measures to achieve the maximum technologically feasible and cost-effective reductions in greenhouse gas (GHG) emissions. California’s overall approach to meeting the goals of AB 32 is described in the Scoping Plan. We analyzed four alternatives to the cap-and-trade regulation: (1) a “no project” alternative; (2) additional source-specific regulations; (3) a carbon fee; and (4) linking California’s cap-and-trade program to a future federal cap-and-trade program. In evaluating these alternatives, we found that none were as effective or more effective than the implementation of a cap-and-trade program in carrying out the goals of AB 32. The cap-and-trade regulation provides a firm cap on 85 percent of California’s emissions. In recommending the specific design included in this proposal, we balanced the need to maintain the environmental integrity of the program, to retain a level of flexibility to help ensure cost-effectiveness, and to consider the potential for co-benefits. We have conducted a thorough evaluation of both the health and economic effects of the proposed program to ensure to the extent feasible that no disproportionate negative impact will occur. We have designed the cap-and-trade program to minimize the cost of implementation and compliance and to maximize the overall benefits. This program represents our continued role to develop innovative air pollution control strategies to help protect California's public health from damage caused by air pollution.

P-3. (multiple comments)

Comment: I am utterly amazed that government at every level seems determined to do everything possible to destroy our already weakened economy with misguided "feel good" legislation and unilateral administration actions. I request that you do your homework, look at the facts not the political imperative, and scrap this horrible plan. (REISIG)

Comment: We have bigger issues in California than to implement a Cap and Trade system. The budget is 25 billion short, we should be looking at ways to eliminate regulations but CARB is set on expanding them. (BOSWELL)

Comment: If this takes place I will not be able to afford to live in California anymore. (DAUKSCH)

Comment: Please think long and hard when you exercise a power as it has a long ripple effect on our economy. What we need is less government and more liberty to move ahead, not to put another drag on our existence. (RATLIFF)

Comment: Please perform your duties in the best interests of the citizens of California and stop the further destruction of California's economy. (VIRGA)

Comment: As I sit and pour over my budget I wonder how I will eat, buy medicine and drive to get my medicine. I will make choices to pay rent or eat or to buy gasoline or meds. California Air Resources Board members add to the problem. You dig into your conscience and pockets and send the old people the money to survive. (HORNE)

Comment: It's not about climate change. It's about Government control, more regulation, destruction of our economy, and the redistribution of wealth. (HARPER)

Comment: The implementation of the regulations associated with AB 32 in these challenging economic times will force undue hardships on Californians. I am opposed to these regulations. (EARLE)

Comment: Implementation of AB 32 will increase gas prices, cost jobs, shut down family farms and make food more expensive. Please reconsider. (THIBODEAUX)

> **Response**: AB 32 requires ARB to adopt regulations to meet the goal of reducing GHG emissions to 1990 levels by 2020. AB 32 directed ARB to prepare a scoping plan outlining the State's strategy to achieve the GHG reduction limit established in the law. The Scoping Plan describes a comprehensive approach that includes direct regulations and a cap-and-trade regulation. The flexibility of the cap-and-trade program, together with specific design features included in the regulation to help contain costs, ensures that the reductions needed to meet the requirements of the regulation are cost-effective. The projected economic growth under the cap-and-trade program would continue virtually on par with current forecasts. Investment in more energy efficient vehicles, buildings, and industrial processes will help reduce fuel use between two and four percent in 2020. These reductions will help offset potential increases in the price of electricity, natural gas, and gasoline. We do not expect the regulation to eliminate existing businesses in California. Cost impacts on consumers would result from changes in energy prices. Incentive programs available to small businesses and consumers will provide access to

funds for investing in energy-efficient technologies, which includes low interest loans, rebates, and credits.

P-4. (multiple comments)
Comment: We really cannot afford to let gross polluters use cap-and-trade to continue their destruction and also to profit from it. We spoke in November and defeated Prop. 23. It is time for you to listen, do the right thing and stop the polluters now. Do not allow the cap-and-trade component of the bill to remain. If you are a polluter then you must stop, now. (RATZLAFF)

Comment: When AB 32 is implemented, please do not financially reward polluters by permitting cap-and-trade. This would substantially weaken the impact of the climate bill. All individuals and corporations must recognize and address the impact that their actions have on the environment. It is very clear that a cap-and-trade option would not result in the necessary reductions in emissions that are essential for a healthy climate. Many experts claim that it may already be too late to reverse the impact that man has made on the quality of the earth's air, water, and overall environmental health, so let's take the first steps needed to stop the insanity. (MAYER)

Response: We have designed the cap-and-trade program to be sufficiently stringent to reduce GHG emissions to achieve AB 32 goals. Covered entities will be subject to an enforceable and declining emissions cap, spurring the installation of more-efficient and lower-emitting technologies. Our analysis indicates that the cap-and-trade regulation is expected to have a beneficial impact on air emissions by reducing emissions of criteria pollutants and toxics, including those from larger industrial sources. Based on available data, current law and policies that control industrial sources of air pollution, and expected compliance responses, we believe that emissions increases due to the regulation at the statewide, regional, or local level are extremely unlikely, at best. Nevertheless, the Board is committed to monitoring the implementation of the cap-and-trade regulation to identify any situations where the cap-and-trade program has led to an increase in criteria pollutant or toxic emissions.

Oppose All Regulations

P-5. (multiple comments)
Comment: Kindly keep this type of legislation out of the State of California. (JORDAN)

Comment: I am absolutely opposed to this nonsense. (COLE)

Comment: The California Air Resources Board (ARB) cannot continue to impose ridiculous emission requirements, etc., without unduly hurting Californians. This must stop. We oppose further controls. (MORRISM)

Comment: There is no need for any of these regulations and nobody else in the world is playing by these rules. (RAPINI)

Comment: Stop it. It will only hurt United States citizens not help in ways you want us to believe it will. (NEWMAN)

Comment: Please just walk away from this awful situation. Please do not do this to our State. You are negatively affecting lives of many people with no solid benefit. It is not necessary to do what you are doing. Just walk away from this huge regulatory tentacle you are wrapping around our State. You must know in your heart that this is wrong and unnecessary. (STEWARTM1)

Comment: What you are doing to our State is outrageous. Stop the nonsense. (VANATTA)

Comment: We do not need any more laws or regulations. Stop drowning people in red tape and paperwork. (WHEELER)

Comment: California must understand that we are not an island in both our environmental regulations and our economic situation. By enforcing overly strict environmental regulations, we make our State uncompetitive with other states and other countries, and since we share the same environment, our contribution to "clean air" is ineffective to change the air quality of the world. Please do not enforce more strict air quality standards than the rest of the USA. (MYERSG2)

> **Response:** Our mission is to promote and protect public health, welfare, and ecological resources through the effective and efficient reduction of air pollutants, while recognizing and considering the effects on the State's economy. The basis for all our programs is research into the causes of air pollution and their effects on public health and the environment. We have developed air quality standards based on our research efforts. Under AB 32 we are required to adopt regulations to implement measures to achieve the maximum technologically feasible and cost-effective reductions in greenhouse gas emissions. The cap-and-trade program is a key element of this overall strategy. The cap-and-trade regulation is designed to minimize leakage. Also, the cap-and-trade program has been designed to be part of a regional trading system. The program design allows linkage with programs established by partner jurisdictions in the Western Climate Initiative to create a regional market system. In addition, it is designed to work in concert with other measures, such as standards for cleaner vehicles, low-carbon fuels, renewable electricity, and energy efficiency. The program will also complement and support California’s existing efforts to reduce criteria and toxic air pollutants. This regulation represents our continued role to develop innovative air pollution control strategies to help protect California's public health from damage caused by air pollution.

Questioning the Public Process

P-6. Comment: I don't know how a majority of Californians support cap-and-trade when I can't find one smart person who even understands it. I have many questions and concerns about cap-and-trade not just for California but for the country and for the world. Where was the California Environmental Protection Agency (Cal/EPA)/Air Resources Board (ARB) Emissions Trading Program and the call for comments published for California residents to read and reply? What does this vote mean? How can my voice be heard? I am against the Cal/EPA/ ARB Emissions Trading Program, and think most Californians, if they really understood what is being promoted, would be against it too. (PERRIN)

> **Response:** We developed this proposed cap-and-trade regulation through an extensive public process. In 2008, we discussed the general framework for a cap-and-trade program as part of the development of the Scoping Plan. The Board included the cap-and-trade program as one of the central measures in the Scoping Plan. We held more than 30 public workshops in 2009 and 2010 devoted to developing the cap-and-trade program design in more detail. These meetings allowed the public to discuss and share concerns and ideas on the appropriate design of the cap-and-trade program. We reviewed hundreds of public comments received from the general public from these workshops. We considered these comments in crafting the design of the proposed cap-and-trade regulation. We have always invited and encouraged the public to take the opportunity to participate in our rulemaking process. Every meeting and all documents related to the cap-and-trade regulation has been and will continue to be available for public review on our website at www.arb.ca.gov/cc/capandtrade/capandtrade.htm.

Q. SUPPORT

This section includes responses to comments expressing support for the regulation. Major topics within this section include support for the cap-and-trade regulation and AB 32, and general support for combatting climate change and making California's air cleaner.

Cap-and-Trade Regulation

Q-1. (multiple comments)

Comment: To think in the short run on this problem can be disastrous. California has to lead the way. Global warming is not going away. It is going to get worse and it will have dire consequences for the human race. Cap and trade is the way to go. (HAIGHT)

Comment: Please support the Cap on Greenhouse Emissions. (ROMAIN)

Comment: We need to have a price put on carbon and a cap-and-trade system put in place. The hoped for results of our State's clean air initiatives and goals will come much sooner if CARB does this. (BUSSE)

Comment: The only way to create a disincentive or to capture the negative externality of poor environmental behavior is to use carbon dioxide taxes as a mechanism. It may not be the final answer but it is the right step and hopefully the first of many steps towards responsible behavior in how we treat our precious natural resources. Please adopt a California Cap on GHG emissions. (CHRZANOWSKI)

Comment: I strongly support passing climate change cap and trade legislation in the State of California. (BRATCHER)

Comment: Stringent steps need to be taken to reduce our impact on our environment. I think a proposed cap on GHG emissions is very important. Research into greener energy sources must be funded. More mass public transportation should be funded, including high speed rail; and decreasing intrastate plane and private car travel. (WENZEL)

Comment: I am in favor of adoption of the proposed California cap on greenhouse gas emissions and market-based compliance mechanisms regulation, including compliance offset protocols. (WELLSTED)

Comment: We are pleased to see strong design features included in the proposed regulations, including sufficiently tight, declining cap; tough penalty provisions; meaningful floor price; auctioning in the electricity and transportation sectors; and annual review. (NRDC1)

Comment: LADWP strongly supports ARB and the implementation of AB 32 to reach the goal of returning the State back to 1990 levels of GHG emissions. LADWP is your partner in AB 32, and we remain committed to making direct investments to dramatically reduce our carbon emissions. Our early actions to date have resulted in a 25 percent drop in our carbon intensity from our 1990 levels. We will continue to transform our generation portfolio by repowering our natural gas plants, investing in more renewable energy resources, expanding our energy efficiency and conservation efforts, and also upgrading our transmission to accommodate more renewables coming into the State. The cap and trade regulation, we believe the way that it is proposed by staff will support these efforts. We look forward to working with ARB staff and to implement the AB 32 program cost effectively and to make it a successful program we all want it to be. (LADWP2)

Comment: Yes to the California Cap on Greenhouse Gas Emissions and Market-based Compliance Mechanisms Regulation. (BURKS)

Comment: It has become very clear to me that there is an overwhelming preponderance of hard evidence that cap and trade does indeed work to first cap and then steadily reduce emissions of dangerous greenhouse gases—and that it leads to prosperity, and not hardship. (KRAEMER)

Comment: The program will help in making California a leader in clean energy, stimulate our economy, and creating jobs. Setting both limits on pollution that decline with time and having a minimum price area is good start. (TERSOL)

Comment: We must act quickly and carefully to bring carbon back under 350 parts per million in our atmosphere. Our coastal communities are facing the possibility of flooding and loss of life. Those with breathing difficulties are threatened. We must cap our greenhouse gas emission for the health of our children. Market-Based Compliance Mechanisms Regulation with compliance offset protocols must be adopted now. (PFEIFFER)

Comment: Please pass regulations that will strengthen California's greenhouse gas regulations. I very much support Market-Based compliance mechanisms regulation, including Compliance Offset Protocols. (KOPPEL)

Comment: Please adopt strong market-based compliance regulations to control greenhouse gas emissions in California. We must be much more aggressive in developing non-fossil fuel energy resources, and your action is an important step in the transition process. (PORTERK)

Comment: Thank you for your excellent work in developing this proposal. We have an excellent opportunity here in California to develop a model market-based system for the entire country. If we can show people that the free market can solve this problem, we have a chance of avoiding the environmental train wreck that we see accelerating around us. A big part of setting up a working market is providing certainty, and the proposed plan addresses this in many ways. (AMENTA)

Comment: Thank you for taking a stand against Global Warming Pollution. This is a big step in the right direction, the opportunity is there to strengthen and cap greenhouse emissions. Setting this wheel in motion on an issue that failed to come together in Washington D.C. will stimulate the creation of jobs revolving around the development of better technologies, manufacturing, and services here in the United States. This in turn will drive down the cost of energy and boost the economic growth of this State and our country. It's a long war against the greed and irresponsibility of the current energy industry. Prop 23 was a battle won and must be used to tighten restrictions and add accountability to companies that harm our health, our country, our world, and our way of life. (SANSONE)

Comment: Thank you for taking climate change and air pollution seriously. As a grandmother, I am terribly concerned about the world our grandchildren will inherit. The rates of pulmonary disease, cancer and other maladies have escalated but no one wants to ask why. I am convinced that pollution must be penalized and carbon and other emissions into our atmosphere must be taxed. (CRAWFORD)

Comment: Two of us here loud and clear----adopt proposed cap on greenhouse gas emissions before all the glaciers melt away. Global warming is real and verifiable and we want our grandchildren safer. (ROCA)

Comment: I think that it is a great idea that California will adopt laws that seek to reduce our carbon foot print each year. I think that this is very important for California to become a leader in strong energy laws. This is definitely a step in the right direction because job creation will increase while at the same time carbon pollution will decrease. This will make polluters think twice and perhaps even actually lead them to conduct their business in a more ethical manner. I support the direction that we are taking. (SUAREZ)

Comment: California has the opportunity to lead the country again, as it so often does. It also has the responsibility to do so because no place on earth is more blessed--not only with beauty and a desirable climate, but also with creative thinkers. If we show the rest of the country that we can lower CO_2 emissions using rational economic strategies, other states will find the courage to follow. The United States, because of California's success, may even begin to take up its responsibility and amend its deplorable behavior in the face of our global environmental crisis. Please act with maximum strength. (SDSU)

Comment: We congratulate you on the culmination of years of work to develop a regulation that puts in place the world's most comprehensive cap on global warming pollution. The cap and trade regulation currently before the Board is a major plank in a comprehensive package of policies that will enable our State to meet its global warming pollution reduction requirements while bolstering our booming clean energy economy, creating jobs, cleaning up smog-forming and cancer-causing air pollution, and maintaining strong economic growth statewide. Californians overwhelmingly support your efforts to enact policies like this to reduce global warming pollution and clean up our energy supply—as the recent election made very clear. (LUDLOW, UCS1, WALTERS)

Comment: One hundred and eighteen Ph.D. economists with expertise in climate and energy issues warned that the most expensive thing we can do is nothing. They urged the California Air Resources Board to proceed in implementing the AB 32 Scoping Plan, stating that "global warming gases will be best managed through a combination of policy approaches. Emissions caps combined with a range of regulatory and market-based implementation mechanisms offer a particularly potent strategy because they provide clear incentives for changes in business practices and the development of new technologies." (LUDLOW, UCS1, WALTERS)

Comment: California leadership in developing and implementing a cap on global warming pollution will have ripple effects throughout the nation and the world. Because the California cap and trade program may become a model for other states and the federal government, it is important that the program is designed to cost-effectively maximize emission reductions in the capped sectors. We applaud CARB for the thorough public process that has led to the proposed regulation and the opportunity for our organization and other stakeholders to work with CARB staff as the regulation evolved to find optimal solutions for many complicated issues. We are pleased to see that the proposed regulation contains several elements that we believe will make the program effective. (LUDLOW, UCS1, WALTERS)

Comment: CCEEB supports adoption of a cap-and-trade program as the best means to achieve greenhouse gas (GHG) reductions at the lowest possible cost and we appreciate the work that ARB staff has done over the last year. (CCEEB1)

Comment: The California Air Resources Board has embarked on an ambitious and worthy goal of reducing the State's greenhouse gas emissions. In this pursuit, REMA expresses its support and continued assistance in developing a climate program that encourages meaningful GHG reductions through both compliance and voluntary actions. (REMA)

Comment: AB 32 is landmark legislation which will revitalize our economy and create American jobs. This legislation is a Win-Win. Please consider the adoption of a proposed California cap on greenhouse gas emissions and market-based compliance mechanisms regulation, including Compliance Offset Protocols. (SOONG)

Comment: I am expressing my support for your implementing a cap and trade system in California. (FREY)

Comment: Please stay strong on cap and trade for carbon emissions. California has the opportunity to be a leader on this issue and to spur other states to act to protect our planet. (SCHERMERHORN)

Comment: I firmly support the adoption of comprehensive cap and trade legislation in California. California must continue to lead the way in the transition to a cleaner economy. (GERDING)

Comment: I am in favor of cap and trade to regulate greenhouse gases. (BARKOW)

Comment: We wish to commend CARB and both the outgoing and incoming Administrations for your collective leadership and determination to design and implement a well-functioning cap-and-trade system for the State of California, which we believe is what has been proposed in this rulemaking. (CLIMATEWEDGE)

Comment: We support market-based mechanisms to reduce greenhouse gas emissions for three main reasons: 1) Job Creation. Clean energy projects create durable jobs that cannot be sent offshore; 2) What is Good for the Environment is Good for Business. When companies invest in energy efficiency upgrades, they not only reduce energy use and carbon emissions, they also reduce their energy bills; and 3) Flexibility. Market mechanisms require companies to reduce carbon emissions, but allow them flexibility in deciding the most economically efficient manner. (MCKINSTRY)

Comment: Overall, we support the cap and trade regulations and believe that CARB has thoughtfully developed a program that will reduce greenhouse gas emissions to help meet the State target in conjunction with the other measures adopted by CARB. (NC1)

Comment: We support the overall Cap and Trade Program being proposed by staff. We commend ARB and staff for this tremendous accomplishment. This is an important milestone not only for the overall climate but also for the recognition that forests and nature must play a role in climate change solution. (NC6)

Comment: Codexis strongly supports the CARB's cap-and-trade regulations as a mechanism to implement AB 32's direction to reduce greenhouse gas (GHG) emissions in California. (CODEXIS)

Comment: I like the idea of making polluters pay for their damage to the environment. I really like the idea to auction the ability to pollute and then use the money generated to fund development of clean industries. (BARRICK)

Comment: I support the California cap on CO_2 emissions and applaud the work that you are doing to implement AB 32. (WAKEHAM)

Comment: Please support expansion of cap and trade efforts to address emissions of global warming pollutants. (JONES)

Comment: Although I would have preferred a carbon tax, cap and trade is a necessary step in implementing AB 32 and in controlling greenhouse gas emissions. I support the proposed cap and the market-based mechanisms. (MATZEK)

Comment: I hope this passes in California and will provide incentives to other states to do the same. We absolutely need a cap on greenhouse gas emissions driven by market considerations, not just "voluntary" compliance which doesn't get us too far. (DEDEKA)

Comment: Please adopt a California Cap on GHG emissions. (CHRZAMOWSKI)

Comment: I am writing to express my support for the California cap on greenhouse gas emissions regulation. As a certified green business owner in the Bay Area, I strongly believe that voluntary changes in the way people do business will not be enough to help curb emissions. (HOUSER)

Comment: Thank you for taking global warming seriously and developing a plan to reduce global warming pollution while at the same time creating jobs and making California a healthier and more prosperous place to live. The proposed program will decrease global warming emissions from the State's largest polluters and establish a market price on these emissions. (MSCG1, FORMLETTER06)

Comment: I am convinced by all I have read that global warming is a real phenomenon, and that it is necessary we minimize greenhouse gas emissions. My understanding of Cap and Trade policies is that they work. We need to put them in place and give the market time to establish. (CSUF)

Comment: Thank you for setting a valuable example to the rest of the country. Getting our carbon emissions down to 1990 levels is so crucial to counter runaway climate change. Persistence on policy is what our scenario needs. A steady price signal will help business adapt. Thank you, again, for your continued efforts. (SUSTAINDESIGN)

Comment: I want to thank you for your work to put a cap on greenhouse gas emissions. I am strongly in favor of the cap and trade regulation currently before the Board. I am pleased to see that the proposed regulation includes: fully auctioning allowances in the transportation sector; strong enforcement; and $10 per allowance price floor. (VARON)

Comment: Small businesses across our states stand to benefit greatly from the incentives of carbon emissions trading system establishes. For that reason, the Air Resources Board should adopt its proposed market system without delay. (SBMAJ1, SBMAJ2)

Comment: The California Energy Efficiency Industry Council supports the adoption of the proposed cap and trade regulations for the purpose of putting a price on carbon.

We believe the regulation will also support a stable energy and business environment that will result in our member companies being able to grow and employ more Californians. (CEEIC1)

Comment: I am in favor of ARB passing the Cap and Trade regulation needed to implement AB 32, California's Global Warming Solutions Act. We can move forward in this country and California has long been a leader for others to emulate. Please pass the cap and trade regulation immediately and regulate greenhouse gases. (GRISHABER)

Comment: Please support strengthening our laws concerning the proposed California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms Regulation. (SPAISER)

Comment: DWR supports the ARB's concurrent efforts to reduce GHG emissions through implementation of AB 32 and the proposed Cap-and-Trade Program. (DWR)

Comment: California Interfaith Power and Light supports the timely implementation of the Cap and Trade program and commends the agency on the release of the proposed regulation. We support many of its provisions. (CIPAL)

Comment: The Council views the draft regulations for a California Cap-and-Trade Program as an important vehicle to reduce greenhouse gas emissions in the western region and the Council congratulates the State for its leadership and action. We support the intent of the regulations to reduce greenhouse gas emissions while creating jobs, providing flexibility to reach emissions reduction goals, and protecting California's economy and we look forward to continue working with you as you refine and further develop the program. (BCFSE)

Comment: I'd like to thank the Board, your staff, and the staff of the EPA for bringing forward recommendations today that Riverside Public Utilities can strongly support. (CITYRIVERSIDE)

Comment: The Bay Area Air Quality Management District is in overall support of the cap and trade rule, which, of course, will be a very important part of the State's overall climate protection program. (BAAQMD)

Comment: I'm strongly in support of the proposed emissions trading program. I think the adoption of CARB standards help to ensure that California remains a center for innovation, job growth, and wealth creation in the new clean energy economy. I'd like to encourage again the passage of the proposed regulation, because I think that it really will help to underpin the kind of growth and leadership that California has been famous for in the past. (JAMBUSE)

Comment: We encourage ARB to adopt the proposed market system that levels the playing field between dirty and clean energy, provides business owners with new opportunities to grow their businesses, and spurs the transition to a low carbon economy. Reducing carbon and increasing efficiency improves the bottom line for our State and for our businesses, giving us a competitive advantage and protecting us from volatile fossil fuel spikes and economic price shocks. (CABAGE1, CABAGE2)

Comment: Thank you for your continued efforts in leading the march toward a sustainable and healthy environment. Your plan to reduce global warming while also creating jobs is a major step in the right direction. Of particular importance is the plan for a steady transition from today's conditions to limits that will produce the desired ends while maintaining economic balance. (TRI)

Comment: This is an essential step to meet the goals. It will end up creating more jobs and new careers for Californians, and will let us become the leader of the nation again. (RAPHAEL)

Comment: I just want to say that I am in support of enforcing legislation that strongly moves in the direction of the proposed California cap on greenhouse gas emissions and that both the private and public sectors need to be made accountable. It is imperative that California continue to be a leader in promoting environmental awareness and responsibility. Sadly, the United States is still far behind many Western European countries when it comes to taking action to reduce various kinds of pollution and greenhouse gas reduction. California can still inspire the rest of the nation if clear, decisive action is taken. (LEVNO)

Comment: I applaud the California Air Resources Board for their work developing the draft regulation. As a California resident, I believe AB 32 is an extremely important means of improving the health of California's citizens, increasing the resiliency of California's natural environment, and securing California's place as an economic leader. The courageous and innovative path the ARB has taken with the draft AB 32 regulation is an example for the rest of the country (and the world) to follow. (SCHUETZ)

Comment: The City of Los Angeles and the LADWP reaffirm their strong support for AB 32 and the goal of reducing GHG emissions back to statewide 1990 levels through a set of measures outlined in the ARB's Scoping Plan, including the implementation of a cap-and-trade program that is well designed and easy to understand. (LADWP1)

Comment: LADWP strongly supports ARB and the implementation of AB 32 to reach the goal of returning the state back to 1990 levels of greenhouse emissions. We thank you, Chairman Nichols, for your continued leadership in this very important policy and regulatory development and for tackling very complex issues that have been put before you. (LADWP3)

Comment: I am so glad that Prop 23 was voted down in the polls, and I am looking forward to the adoption of a cap on greenhouse gas emissions. As a Californian deeply dedicated to working toward a more sustainable society, I urge us all to continue doing what we can to make our future cleaner and brighter. By making it more difficult for the world-polluting status quo to remain, we will see a surge in new development and technology. Please strengthen regulations and help move us even further forward. (MILLERJEN)

Comment: Thank you and please continue to take a strong position on greenhouse gas emissions control in the State of California. I fully support 'green fees' on all sorts of emissions and on waste that results in more emissions. California can be a leader in instituting green fees to curb corporate and individual citizen behaviors that pollute. I don't support a cap and trade program that uses the stock market, but I do approve of a state run gradual reduction of emissions through state fees, that captures those fees and uses them to make other efforts to ameliorate pollution. (MORSE)

Comment: The last thing we need in our State is to weaken our pollution controls. We need strong laws that set caps on gas emissions. (COOPERKEIL)

Comment: We are strong supporters of the need to establish and maintain cap and trade practices here in Calif. Our State can show leadership that other states and Washington DC can follow in this and other regards when it comes to protecting our environment and developing realistic and credible alternative fuel sources. The lives of our children and grandchildren depend on us doing these things. (SOLOMON)

Comment: The current CARB program in California is important to reach the State's goal of reducing global warming emissions to 1990 levels by 2020, along with renewable energy, energy efficiency, and cleaner transportation standards. Forcing polluters to pay for the emissions they generate by purchasing permits in an auction, the auction funds can then be re-invested into efforts that will help us transition to a cleaner economy and help lower energy costs for Californians. Thank you for your time and all the work being done in this regard. (FISH)

Comment: In general, we strongly support the State's development of a cap-and-trade program and believe that CARB has thoughtfully developed a program that will reduce greenhouse gas ("GHG") emissions and help the State to meet its mandated emission reduction targets under AB 32. (COPC1)

Comment: I strongly support the official statement of the Union of Concerned Scientists concerning the implementation of GHG emissions capping. The strong public support of Proposition 23 is a public mandate of strong GHG reduction laws. Global warming and the need to free ourselves from dependence on fossil and nuclear fuels are the most serious issues facing the human community. Please treat these issues with the serious, energetic and ethical commitment that they require. (PARLETTE)

Comment: I have some misgivings about Cap and Trade as a means to address global greenhouse gas emissions. But I think it is good idea to try it. As we know it has worked on sulfur dioxide emissions and to stop acid rain. California's nation-scale economy is a good place to test it out. As usual the devil will be in the details. But go for it. (CARMICHAEL)

Comment: I implore you please strengthen the programs that will be implemented to limit global warming emissions and establish a fee for polluters. This is long overdue. A much stronger California Cap on Greenhouse Gas Emissions program including Market-Based Compliance Mechanisms Regulation and Compliance Offset Protocols is absolutely necessary not only to help stop Global Warming, but also to protect the citizens of California from becoming sick with a myriad of upper respiratory diseases—many of which are incurable. (POWERSW)

Comment: Who are we kidding but ourselves? As usual we, humans, are hiding our ostrich like brains in the sand. Let's fix this now. Oh, there is not enough money. Cheaper now than later. (SARRIS)

Comment: Cap and trade is a great system and should be strengthened not weakened. (MCCARTER)

> **Response:** We acknowledge your support to move forward with the cap and trade regulation.

General Support for Climate Change & Clean Air

Q-2. (multiple comments)
Comment: I urge you to do ALL you can before it is too late. Our planet is getting warmer by the day and every day that passes, we will have to do more to counteract this. The scientists have spoken. It is now time to move full speed ahead and act on their advice. (NEAL)

Comment: California has been a leader in the past and needs to continue that role. Moving ahead with techniques to halt global warming will create jobs and improve health for all of us. Improving health will save money in long run. Let's take this on and become the leader and example for others. (RENTON)

Comment: I commend you for the immense responsibility you have taken on. I think debates on global warming can go on and on forever; however, increasing pollution damage and the major causes are obvious. I urge you to think long term and vote for policies that hold polluters accountable commiserate with the (short and long term) damage they cause. Without clean air food and water, nothing else matters. Thank you for reading. (REILLY)

Comment: I would like to express my appreciation to CARB for their continuing efforts to ward off the disastrous effects of climate change that daily quickens its pace. My expertise is in the treatment of wastewater and solid waste wherein by the total use of anaerobic processes makes possible the complete elimination of billions of tons per day of GHGs in wastewater treatment alone. Only the concerted action of bodies such as yours will break the lethargy and overcome the inertia of current practitioners in this field, a field wherein answers to these problems are and have been available for some time and more will arise and be put into practice with your encouragement. I thank you for what you do. (ENVDEVELOPERS)

Comment: With our long coastline and exposure to climate changes due to ocean warming and global warming, we Californian's NEED you to keep to a strong course with regard to carbon emission control. Don't let yourselves be distracted by the deniers, who appear to be happy about sacrificing their children for short term gain. Don't sacrifice ours. (CASPARINST)

Comment: Please make sure that CA gets the kind of climate rules that will save our air and our water. I am an asthmatic and would be more than grateful for a break so I can breathe. (SEAMAN)

Comment: I am writing to urge officials to vigorously enforce the California law regarding meeting the challenge of climate change. I was proud of Californians for rejecting the attempt to overturn this law in November. My feeling is this: nobody should have the right to pollute the air and water because it is essential for all life. Whatever it takes to make the large polluters invest in drastically reducing the threat to life should be pursued with everything we can muster. Please do not let delay and inaction rule the day. The "tipping point" may arrive sooner than it was thought. (THOMAS)

Comment: I urge you to adopt the strongest possible plan to mitigate greenhouse gases. This will not only be good for the environment, but also good for California's economy. One of the real growth areas of the future is green technology, and this will help that market develop. (SIMON)

Comment: Although I believe cap-and-trade policies are of little value and cannot reverse the accumulation of greenhouse gases in our atmosphere, I will support anything you can do to help address this problem. You are on the front line of U.S. response to climate change. Please do everything in your power to help alleviate this growing threat to our coastlines, our country, and the world. (USD)

Comment: As a recent volunteer on the No on Prop 23 effort in the San Diego area, I wanted to encourage you to keep California's global warming laws as strong as possible, to ensure California meets and exceeds its reduction goals. Californians have demanded it! (DISENHOUSE)

Comment: California should be a leader in this arena. I whole heartedly endorse taking the necessary steps to put California in that position nationally and globally! (SCOTT)

Comment: I support California's efforts to reduce greenhouse gas emissions. Green energy such as wind and solar creates jobs and innovation and puts California, and then the nation, further ahead in adopting new technology and fighting for our environment and our future. (JOHNSONR)

Comment: I commend the efforts of the California State EPA, its Air Resources Board, and I ask you to challenge other states and territories, and you already have. I can only hope our successors find our movements towards a more secure climate, and therefore, future, worthy of respect: hopefully, for your State and the State of New York, real pride for your leadership. I should hope that our states and territories might enter into a friendly competition towards circumspection and better valuing what we've been gifted with: such amazing resources, and a nation of great talent and energy. We have all we need, really, at hand, to prepare for, re-think our society for, a time with very different energy resources. Please continue your efforts, and know you're helping set a standard for all of us. (JOHNSONA)

Comment: I'm writing to thank California for taking aggressive action to lower your State's greenhouse gas emissions. Global warming is the greatest threat facing humanity today. Qualified scientists indicate quick action is necessary to limit the worst impacts. I appreciate California's efforts to curb greenhouse gas pollution. (CRUPI)

Comment: So impressed to hear the people of California and New York are taking measures to ensure their health as well as the health of the environment. We need to take control of these important and necessary issues concerning the climate. (TOUCHSTONE)

Comment: Thank you for taking proactive steps to counter climate change. Your leadership sets an example for the rest of us. (PLANK)

Comment: Thank you California for leading the way on climate action when our federal government has failed to act. I hope you can inspire other states to follow along (like my State of Maine). (WOLPOW)

Comment: Thank you California for showing leadership and foresight in addressing climate change. I am disappointed with the lack of action at the federal level and as a resident of Texas do not have much hope of action by my State. However, in many environmental causes, CA has taken the lead and the rest of the nation has followed. I would like to add my voice in support of legislation limiting the emission of greenhouse gases. (DILLER)

Comment: Thank you for leading the way for climate change action. We expect other states to do the same. There will be many jobs for "going green" and the sooner we make changes the less drastic the climate change negative effects will be in the future. (PRICES)

Comment: Please continue to uphold California's leading role in tackling climate change and the other destructive effects of industrialized, consumerist society. Don't let the ignoramuses get you down. (RIEBEL)

Comment: Let's strengthen California's fight against global warming. (LEVIN)

Comment: Don't pay any attention to any "climate deniers." They only want to twist things in their favor and no one else's. (HARRINGTON)

Comment: Please do everything in your power to reduce greenhouse gas emissions. My children and grandchildren are depending on it. (MAYWALD)

Comment: So far, California has been the poster child for a positive response to climate change and the way into a healthy future for the planet. Please do not drag your feet now. We need to move ahead and keep our progress going. Not just to stay #1, but for the sake of our citizens and for our State. We love this State and want it to rise to its full and green potential. People are not going to want to put up with heel draggers when it comes to the welfare of our State's green qualities. Not only is its greenness our biggest health advantage, it is also our biggest advantage for business and the economy. Be green or leave the scene will be the judgment. (KEITHLEY)

Comment: Thank you for taking a pro-active stand on controlling greenhouse gas emissions. It is important that the standards be upgraded as we begin to see the dire effects of greenhouse gas emissions. Global Warming is real. California can set the standard, other states will follow. (KAUFMAN)

Comment: I wanted to urge officials in charge of implementing California's landmark global warming law to be as aggressive as possible in taking actions to curb harmful emissions and achieving the other objectives of our law. Polluters and their representatives and their idiotic references to global warming as a "hoax" must be completely disregarded. Polluters are the problem and it is time they begin to pay all of the extra costs of pollution that citizens have already been paying for years. Thank you for your time and attention. (HORWITZ)

Comment: I am pleased that you have opened up the discussion on greenhouse gas emissions so that the public can have a say in the final wording of the rules. The public has expressed its interest in good environmental policy when it turned down the proposition that would have made it difficult if not impossible to adhere to the environmentally sound conditions which were passed recently. I hope that you will remember this when you finalize the rules for greenhouse gas emissions. Specifically, I hope that you will require the polluters to take their share of responsibility for pollution they have created. Thank you for opening this up for public comment. I am sure you will do the right thing if you follow the wishes of the citizenry. (FESSENDEN)

Comment: The rapid rate of climate change is requiring us to react quickly and creatively. Thank you for the proposals by the State of California. I hope you will move with strength and resolve to start us on the road to healing our planet so we can all live safely without droughts, floods, severe storms, loss of shore line etc. The sooner we begin the less draconian the measures will need to be. (BJELLE)

Comment: Global warming is a very serious issue. Anything you can do to cut down on greenhouse/methane and carbon gases would benefit the planet a great deal. The polar regions are melting, there are dead zones in our waters and mankind's neglect is the cause. Let's turn it around before we're past the point of no return. (ACKERMAN)

Comment: As an environmental engineer, I can tell you that the need to reduce the output of carbon dioxide and other greenhouse gases to the atmosphere is urgent. Please enact a strong climate change mitigation program and lead the way for the rest of the country and the world to do the same. The new program must include significant fees for polluters, not credits to be given away and traded like playing cards, which will not work. It must also include strong new fuel and energy efficiency standards. We must get this right. Our future depends on it. (PETLOCK)

Comment: Please up hold and strengthen California's greenhouse emissions protocol. (HARRISONE)

Comment: The science is overwhelming at this point and almost all opposition to coming regulation comes from hacks that are either directly funded by various arms of the fossil fuel industries or are reps from those industries. It is up to us to show the path to the future. The time to act is now and you have a clear message from the voters who turned down the trojan horse of proposition 23 funded by the fossil fuel industry. U.S. citizens are willing to pay more for real change and to grow the new energy economy now here in California. (PATTON)

Comment: First, thank you to the Board for creating and pushing the GHG emissions regulation making CA the first to genuinely attack global warming. As a resident Californian, I urge you to move forward on the regulations in the midst of what will be massive opposition from the powerful oil, gas and coal industries, and heavy industry. Do not let them bend you will, or the will of Californians. (HOOPERASSOC)

Comment: We have to stop energy production that creates greenhouse gases now and put our efforts into alternative energy production sources. You can be a leader in this. We all can benefit or will suffer by your decisions. (KAISERS)

Comment: Thank you for your work on climate change. (FUTRELL)

Comment: Thank you for taking global climate change seriously. A plan to reduce pollution while rebuilding jobs is not only good for California it is good for all of America and the world. (CADMANS)

Comment: I want to thank you for taking global warming seriously, believe it or not there are global warming deniers out there, even at the highest levels of government. (NGUYEN)

Comment: Thank you for your work over the years in leading the nation on the important issue of combating man-induced climate change. Please do not back down in your regulatory duties in bringing California (and perhaps by example the rest of the nation) onto a path of eventually decreasing CO_2 emissions. It is already too late, but still, better late than never. Thanks again for your work. (USGSRETIRED)

Comment: Please make sure the future of our children and our grandchildren will be a good one. Make sure California leads the fight to stop global warming. (SAUNDERS)

Comment: I urge you to resist the pressure of industry to grant a high level of free giveaways. Californians are ready for tough regulations to reduce global warming. And the world will be watching. I urge you to make care of the planet your top priority. (OSTWALD)

Comment: With the exception of a minority of right wing religious fanatics and the internationally powerful oil industry's dependence on the present course of depleting the earth's resources regardless of the consequences we have overwhelming evidence, both scientific and practical, of our urgency to do what is necessary to reverse global warming. (WILCOX)

Comment: Please know that I want a future for our children with health and safety and a planet that can sustain healthful life. Thank you, for remembering this and doing what may not be fiscally popular but morally right. Remember to make a decision to ignore the possibility of climate change will be catastrophic. Please let us not make irreparable mistake. (HANSEN)

Comment: Listen to the scientists, than act in the best interests of our State and our people. Time is running out. (BEDECARRE)

Comment: I urge you to create even stronger guidelines to promote a cleaner California environment. While I am just an "average" citizen, I am relying on my government to ensure a healthy environment for people like myself with asthma and other lung conditions. I am also relying on my government to promote green technology and to move California into an infrastructure that embraces the necessary changes to a green energy grid. Please do not be swayed by the emotional arguments of the global warming naysayers. The world scientific community has proven over and over again through meticulous research that our environment is imperiled by habitat loss and global warming. (POLANSKY)

Comment: California has a good law regarding pollution and global warming. We should do all we can to strengthen it and not punch holes in it. Polluters need to clean up their act. Do not allow them to buy their way out of their responsibilities. (COMMONS)

Comment: I'm a Los Angeles citizen and I am very much in favor of regulating greenhouse gasses. (IRELAND)

Comment: Jobs will be created if all of the goals of AB 32 are implemented. If some polluters are let off the hook, what will that do for the economy? Nothing. Please hold the line on all of AB 32. (STOLTZFUS)

Comment: I want to thank you for moving forward with the implementation of AB 32 and applaud your leadership on this important issue. The November elections make it perfectly clear that Californians care about this issue and want their leaders to see to it that our environment is protected. Already important actions have been taken. However, I would like CARB to make sure all industries are accountable for the pollution they emit. Please see to it that all industries contribute their fair share of resources and abide by the highest mandates so investments can be made to begin the change of a clean energy economy. Thank you for your time and leadership. (WESTERNS)

Comment: I'm writing to show my support for AB 32. (GROTHAUS)

Comment: Please execute AB 32 as was intended and enlarge those directives to take as aggressive a stance as possible. It's time to do the right thing by not only Californians who want to lead the way in the U.S., but ultimately, for all the earth's people. (CRAWFORD)

Comment: We support the creation of a robust clean energy economy in California and do support your implementation of AB 32. (CABAGE1, CABAGE2))

Comment: We were very glad to see that AB 32 saw overwhelming public support as witnessed by the defeat of Proposition 23 in the recent elections. (GLOVER)

Comment: California has a proud tradition of leading the nation in smart, new policies. AB 32 is a prime example. It's imperative we don't miss our chance to give small business owners the help they need during these tough economic times, because it's our creative entrepreneurs who will lead the way in restoring our State's economic vitality. (SMMAJ1)

Comment: Please fully implement AB 32. This landmark piece of legislation will go a long way to addressing a critical problem in our society (global climate change). (WHITEK)

Comment: I urge you to stake a very strong and committed stance regarding the implementation of the goals of AB 32. Global warming is a critically important problem that should be addressed and I am grateful for the existence of this key legislation. (CHRISTJANER)

Comment: We believe in the AB 32. (FORESTWATCH)

Comment: We really endorse the goals of AB 32. We poll our customers to see what they like. Do you support all of the goals of AB 32, environmental responsibility? And they do. And they also support rate increase for that. Slower smaller rate increases but sustained. (CITYRIVERSIDE)

Comment: The State Hispanic Chamber supports the goals of AB 32. (CAHISPCMBR)

Comment: I strongly endorse AB 32 and suggest increasing the tax on gasoline, and the number of tree planting projects. Have a book of global warming with clear evidence compiled so that naysayers cannot argue. (KNIGGE)

Comment: Thank you for taking global warming seriously. (COHEN1)

Comment: The people of California have spoken and they want teeth in the implementation of Proposition 23. Don't cave to corporate interests. There's nothing wrong with making the polluters pony up as long as it's a level playing field. Make that playing field stringent and then enforce the hell out of it to keep it level. (DIAMOND)

Comment: I applaud your efforts to reduce greenhouse gas emissions. Personally I'm not well informed on the "cap and trade" approach and am inclined toward improved technologies as a preferred solution but any and all efforts must be taken to deal with this critical situation. (RADCLIFFE)

Comment: California, the car-drivingest state, has taken admirable steps to slow down the human causes of global warming. Other states and whole countries will follow sooner or later. Coal-mining states will have the hardest transition to new industries and jobs. Yet without PRC China's fullest effort to change from coal energy, the jig is up for our unique Planet Earth. Avoiding climate catastrophe would have required human behavioral change on a massive scale. (HECKMAN)

Comment: I will make this short and (bitter) sweet. Do something. Lead like Californians do. Set up the goals and compliance to clear our air. The rest will follow. The argument will be we will lose jobs, it always is. It won't happen. Gone should be the days that the public pays the price for companies "rights" to profit. (POUSMAN)

Comment: The stronger your sanctions for pollution, the greater the chances are that the oil and gas industry will diversify and create jobs in the alternative energy (green) sector. You must hold the line on accountability, particularly since at the other end of our country, when the new House sits in D.C. in January, coal will become king again and California will be the sole light at the end of the global warming tunnel. Brace yourselves for the attack and stand firm. (LANE)

Comment: We must make this new law as strong as we can and to let not only the rest of the USA but the world know that there is no turning back now. California will lead the world in making our air the cleanest it can be and we need to make the polluters pay and pay big time. (WARNER)

Comment: Anything we can do to slow climate change should be at the top of our list. (CASTLEREY)

Comment: I urge you to take the opportunity to strengthen GHG and Carbon emission regulations to decrease the levels of emissions. Carbon Dioxide and many GHG gases are known to harm our health, environment, air quality, and dramatically impact climate change. Please take a bold, positive stand to regulate these gases and emissions that will make a positive impact on our health and our environment. (RICHARDS)

Comment: California must lead in clean air as clean air is better for the people who live in our State. (WANG)

Comment: Go for it. Show the rest of the nation what can be done by planning and commitment. (BRENNAN)

Comment: I want to extend my sincere thanks to you for making California a cleaner place to live. I can remember "smog alerts" as a child growing up in Los Angeles, when we were restricted from playing outdoors. Air pollution makes my asthma and my heart condition worse. Your work to keep our air pure has a measurable effect on my quality of life. Thank you. (LAUMANN)

Comment: Everything possible should be done to protect our air and our planet. (SOBO)

Comment: I thank you for realizing the importance of our clean earth but there is still a ways to go and we cannot cave to the other side’s ridiculous arguments. We must move forward with what we know is right and hold all wrongdoers accountable. (PERATA)

Comment: Continue California's trailblazing work by promoting and upholding the highest environmental standards. (TAYLORC)

Comment: Strong regulation is a win-win for the State as it will create green jobs and protect our environment. Please adopt the most robust regulation possible. (GIBBS)

Comment: Please stay on track with controlling emissions!! Don't let this opportunity slip by us. (ERILANE)

Comment: Please do your part to help the earth's air—our only air. (LITWIN)

Comment: Please support the California League of Conservation Voters and other Earth friendly groups in their attempt to save our planet and our lives. (CHITTENDEN)

Comment: Thank you for all that you are doing to try to insure a future for our children, and their world. Please consider the whole earth when you make your decisions. (CADMANL)

Comment: Thanks for what you are doing. A clean environment is best for everyone. I guess unless you just want to be as rich as possible then die before there's no fresh air left. (BROWNRO)

Comment: Please do not continue to compromise our health any further by allowing more pollution of the air, water, and food. (HARRISV)

Comment: Please keep California's air clean. Do not give in to the political pressure to weaken emission compliance. (REGINATO)

Comment: Please help us create policies that put science and sound stewardship of our environment before corporate profits. (BERALL)

Comment: We are long overdue in addressing the need of the country in being forward thinking on the environment. We must act swiftly and decisively in order to slow the degradation of our natural world. Our very lives depend on it. (ANDERSONL)

Comment: As a person who is in poor health I need good non-polluted air to breathe, please fight for me. (JACKSON)

Comment: Please help the world by having the government go green! (MYERSR)

Comment: Clean air & water will allow the planet to continue to live and assist us in having healthy bodies. 99.9 percent of all cancers are from toxins in the air, food, and water. Most corporations, including oil companies, hide the information that protects their money and destroys wildlife, plants and people. If you want to have a healthy lifestyle and body or have children, grandchildren OR anyone you love to stay healthy—please help in any way that you can. (BURDINE)

Comment: It all comes down to a very simple statement. Save it now, or lose it all latter. Your choice. (BILLER)

Comment: With the economy, the environment and our world on all levels is going through massive change. It does not look good for our future generations. I ask that you please think of our children's children's children so we can leave them a planet. Let's think far beyond our immediate future. That is all I ask, and let your consciousness decide what is correct. (MONTANA)

Comment: We live in the Sierra Foothills, especially in Nevada City. You'd think being "out in the country" would be healthy. Yet our area is ranked as one of the highest pollution areas, because much of the pollution from the Bay Area is carried by the winds and blocked in our area by the mountains. Please curb the pollution, tighten restrictions, and put incentives for going GREEN. Our State and country and world need this. (OLSON)

Comment: The problems we've had in every other area of our society come from laissez-faire "free market" or "market-based" decision-making. But there are some things that you can't put a price tag on, and don't belong in the equation in the first place. Above all, we must protect our environment and our air quality. (LYONM)

Comment: Please think of the future of our children and you immediate voters! Our issues survive and your vote keep coming be present to the future of our needs and yours. (HARRISONT)

Comment: Thank you for responding so well to the threat of global warming. California ARB has lead the nation many times, taking action when scientifically validated, instead of waiting as industry and other vested interests attempt to stall action. Your plan to reduce global warning emissions, while creating growth (jobs) through renewable energy and other technologies, is commendable. My family has taken steps to reduce our carbon footprint--reducing use of water, electricity, and gas, driving fuel efficient vehicles, recycling, composting, etc. Some businesses and trucking companies have taken steps too, but their investments will cost them a competitive edge if other companies do not make similar changes. Please do not back down from the political pressure. Californians and other Americans are counting on you. (MILLS)

Comment: Please, no more ecocide for the short-term benefit of the fossil fuel industry. We need cleaner air, cleaner jobs, cleaner energy, better health and greater security. Take stronger action now and lead the world to stop delaying the death of the fossil fuel industry. (BROCKMAN)

Comment: I believe that California can create an entirely new economy that is based on sustainable and renewable goods and services in all aspects of life. But this could never happen if we are lax with our clean environment laws. Stay strong and uncompromising, because 'big oil' isn't the only option we have. (ROBBINS)

Comment: California is in a position to lead our nation into a future of sensible controls on pollution and promoting sustainable energy use. Please do not let this opportunity pass. We need to turn around the senseless idea that jobs and growth depend on continued use of fuels that pollute. (FRIEDMAN)

Comment: We need to set a very strong example here for several reasons. If California can show the way towards alternative sources of energy and meaningful reduction of greenhouse gases, perhaps it will start a worldwide trend to follow our lead. (ENEVOLDSEN)

Comment: It is encouraging to see California leading the way scientifically by following the lead of the 97 percent of climatologist who warn us against the threats of global warming rather than listing to the 3 percent deniers. If history proofs the 97 percent to wrong, we still will be better off developing cleaner more renewable sources of energy that can help us to overcome our addiction to fossil fuels. Continuation of our fossil fuel addiction is a losing proposition no matter what. Thank you California for leading the way to the future. (LOMAX)

Comment: We need to do everything we can to convert to a green economy. The vested interests in oil, natural gas and coal have a lot of money and will do everything in their power to try and make sure they get to burn up every bit of fossil fuel in the ground. But the atmosphere is already overloaded with carbon and we just can't burn the remaining fossil fuels without horribly damaging the Earth's ecosystems. So please stand strong and protect the atmosphere and life on Earth from carbon pollution. (FRETHEIM)

Comment: We must have realistic and powerful restrictions placed on the fossil fuel industries for there is very little time left to reverse their devastating effects upon our citizens' breathing, as well as climate change. It is a dire situation which needs emergency legislation. Please do what is necessary for both humanity and every living thing on this planet. We can easily progress well beyond this petrochemical age of massive pollution. (JOHNSONS)

Comment: I want to encourage the Board to set stringent standards in order to wean us off of fossil fuels and to move us toward greater energy independence by embracing clean technologies such as wind and solar energy. Nuclear fuels are too dangerous and we have no permanent storage capacity for them. By focusing on renewable energy sources (nuclear not included here), we can create a much better future for everybody in our great State. (STEELEB)

Comment: We urge you to strengthen the proposed program for decreasing global warming emissions from the State's largest polluters. It is the right thing to do. As goes California, so goes the nation. It is not just a catch phrase, make sure you don't sell us out. (RITCHIES)

Comment: Thank you for protecting the environment for my future kids. I encourage you to continue to strengthen the global warming program further. It's worth any cost. (DELATTE)

Comment: Thank you for your efforts to reduce global warming emissions. I am writing to ask you to consider strengthening the proposal. (DUTTON)

Comment: This is not the time to weaken our air quality standards but to strengthen them and ensure that we have the regulations and enforcement mechanisms in place to keep improving our air and that we continue to support those policies that will ensure a future of clean air for all Californians. (LOZANO)

Comment: Clean air is what we need to have, in order to live a healthy life. Please strengthen and reinforce the California Clean air laws. (OFFEN)

Comments: Air quality should be strengthened to also include wood and coal burning restaurants that contribute to local pollution by emitting additional harmful smoke and carbons into the air. (AMOUR)

Comment: Thank goodness California voters and governmental officials have demonstrated overwhelming support for taking action to protect us from devastating climate change. Please keep up the good work and move regulations in the strongest possible direction. (WITTWER)

Comment: To avoid climate catastrophe, greenhouse gas emissions in the U.S. must peak in the coming decade, decline steadily, and reach a level close to zero by mid-century. I support any effort to accomplish this goal, for the health of our planet, ourselves, and generations to come. Let's lead, California. (HASKETT)

Comment: As a Dentist, I am deeply concerned about Green House Gas emissions and what pollution means for the health of our citizens. I applaud the steps being taken in California to lower emissions as a part of a greater movement in our State to ameliorate climate change and keep our air clean. (STEINBORN)

Comment: We in California deserve to have clean air to breathe. We vote for it and demand that our elected officials make and pass rules, laws and regulations to make that happen. (MILLERF)

Comment: Congratulations! You will be a positive example for the rest of the world-go for it. (KNOTH)

Comment: I support the environmental protection standards. (WILLIAMSA)

Comment: I am writing simply to send my heartfelt thanks for your state's leadership regarding reducing emissions that worsen global warming. (HURLEY)

> **Response:** We acknowledge your support on climate change and our efforts to reach the greenhouse gas (GHG) reduction goals required in the California Global Warming Solutions Act of 2006, Assembly Bill 32. These programs will also help reduce smog-forming pollution and air toxics.

Support GHG from Biomass Waste

Q-3. Comment: We support the proposed rule consideration of GHGs from biomass wastes as excluded from allowance requirements. This is consistent with other cap and trade programs, and recent U.S. EPA guidance which allows permitting authorities to take into account the environmental, energy, and economic benefits of biomass during Clean Air Act Permitting for Greenhouses Gases. (PCAPCD)

> **Response:** We acknowledge your support.

R. USE OF AUCTION PROCEEDS

This section includes comments and responses concerning how allowance auction proceeds and consignment auction proceeds are utilized. Suggestions for use of auction proceeds include creation of a Community Benefits Fund to assist communities already affected by air pollution, return of proceeds to consumers, assistance to small businesses and local governments, creation of a low-carbon technology investment fund, and investment in renewable energy and energy efficiency.

Air Pollution Control Fund

R-1. Comment: We support the deposit of allowance auction proceeds into a common fund such as the Air Pollution Control Fund, as identified in the final regulation (Subarticle 8, section 95870(f)). While the legislature may ultimately appropriate these funds, TNC urges CARB to amend this section to identify that these funds should be invested in ecosystem-based adaptation, land use, transportation and a community benefits fund for use by qualified organizations and local governments, as they were explicitly identified in the final March 2010 recommendations of the EAAC. While the EAAC report recommends the auction of emissions allowances as the most equitable and efficient way to distribute allowances to capped entities, it also recommends the distribution of allowance revenue to ecosystem-based adaptation, among other important investments. It is critical to dedicate funding to ecosystem based adaptation. Proper investment of allowance value will help minimize the negative effects that excessive greenhouse gas (GHG) emissions are having on California's natural systems, and by extension public health and safety. It will also simultaneously protect the vital GHG mitigation function these systems naturally provide. Allowance value investments and compensation should be dedicated to all natural systems in California for adaptation purposes, including forests, grasslands, working landscapes, coastal areas, watersheds, and deserts to protect and promote their vitality and diversity and the many benefits that they provide to Californians and the economy. These benefits include, clean drinking water, climate regulation and carbon sequestration, air quality protection, flood control, wildlife habitat, crop pollination, recreation, timber, and employment, among other things. The public cannot afford to lose these benefits, and the State has an opportunity to optimize its investment by dedicating a significant portion of allowance value to these resources. (NC1, NC7)

> **Response:** In Resolution 10-42, the Board directed ARB's Executive Officer to deposit a minimum of 10 percent of annual proceeds generated from the direct auction of allowances into the Air Pollution Control Fund for appropriation by the Governor and Legislature for programs and projects that reduce greenhouse gas emissions, mitigate direct health impacts of climate change, and promote green collar employment opportunities in the most impacted and disadvantaged communities in California.
>
> Also, in Chapter II of the Staff Report, we discussed the creation of a Community Benefit Fund to recognize the community protection goals of AB 32. Although

> ARB is precluded from establishing a regulatory program for a Community Benefit Fund until and unless authorized to do so by the Legislature and the Governor, the Board did direct the Executive Officer to initiate a public process to develop recommendations to the Legislature and Governor on the types of projects and programs to be funded. We encourage participation in the public process, and believe that appropriate recommendations will be developed and proposed to the Legislature and Governor.

R-2. Comment: The cap and trade regulation should explicitly include clear language on the investment of allowance auction proceeds in ecosystem-based adaptation and the preservation of our natural infrastructure for its climate benefits. Modify section 95870(f) as follows:

(f) The proceeds from the sale of these allowances will be deposited in the Air Pollution Control Fund and will be available for appropriation by the Legislature for the purposes designated in California Health and Safety Code sections 38500 et seq. <u>and may be used for purposes of ecosystem-based adaptation, the protection of public health and disadvantaged communities, land use and transportation, greenhouse gas reductions by local governments and a community benefits fund, as advised by the Economic and Allocation Advisory Committee in its March 2010 report to the California Air Resources Board.</u> (PFT1, PFT2, NC2)

> **Response:** Auction proceeds placed in the Air Pollution Control Fund will be made available for appropriation by the Governor and Legislature for purposes outlined in AB 32. Therefore, we do not believe it is appropriate to modify section 95870(f) as proposed.

Community Benefit Fund (CBF)

R-3. (multiple comments)
Comment: Set aside a minimum of eight percent of allowances to benefit disadvantaged communities. Sell eight percent of allowances to entities covered under the cap at the program's fixed floor price. A minimum of eight percent of allowances is equivalent to the offset limit percentage in the proposed regulation and ensures that the CBF program is large enough to be meaningful and attract sizeable private investment to help create jobs which are most needed in these communities. Place the revenue received from this sale in the Air Pollution Control Fund (APCF) to ensure its availability for appropriation by the Governor and the Legislature to create the Community Benefit Fund (CBF). Include a requirement that the CBF shall be used to fund programs or projects that reduce greenhouse gas emissions, mitigate direct health impacts of climate change, or promote green collar employment opportunities in the most impacted and disadvantaged communities identified by ARB. The emission reduction programs funded by the CBF will reduce burdens significantly and maximize the co-benefits as required by AB 32. Selling a portion of the allowances at the floor price ensures a predictable revenue stream to plan and implement the CBF program successfully across the State in the identified communities. The floor price eases the financial burden of entities covered by the cap and reduces the price spikes associated with

auctioning. Creating the CBF at the beginning of the program will garner wider support for the overall program (which is vital for its sustainability) from many environmental, community groups, impacted neighborhoods and potential applicants (including small businesses, local governments, etc.) as well as legislators. (CCA2)

Comment: At a minimum, CARB should definitively establish a community benefits fund (CBF) and give stakeholders greater confidence that a CBF will be funded sufficiently with revenue from the sale of allowances. EDF joins our colleagues in GWAC in encouraging the setting aside of allowance value for the CBF. (EDF1)

Comment: Greenlining recommends that CARB include provisions in the regulation that set aside funding for CBF. The funding will be used to mitigate the impact of climate change and air pollution, improve community health programs, and promote green workforce development programs. CBF should only be available to communities that are disproportionately affected by climate change, and Greenlining will work with CARB to identify the most vulnerable communities. Our multi-ethnic and multi-sector collaboration experience will help CARB reach out to communities effectively. The creation of a green technology workforce training program to help workers transition to the renewable energy sector is crucial. (GREENLINING1)

Comment: Though it did not pass, the inception and development of AB 1405, De León, California Global Warming Solutions Act of 2006: California Climate Change Community Benefit Fund, provides a framework that ARB staff could use with amendments. We recommend allocating no less than 30 percent of the total revenues generated from the annual purchase of allowances and offsets that will be allocated to CBF. The revenues should directly benefit local communities most impacted by climate change in California to mitigate the costs of reducing carbon, which disproportionately falls on low-income communities. (CBE1)

Comment: While we appreciate the inclusion of a recommendation in the Initial Statement of Reasons (page II-29) to the Legislature and Governor to establish a Community Benefit Fund (CBF), we are disappointed that such a mention is not included with further detail in the regulation to ensure the CBF is initiated by CARB at the onset of the program, beginning in 2012 when auctioning and sale of allowances will begin. We believe CARB has the authority to initiate the CBF by providing a specific amount of funding into the fund from the beginning, while still recommending the Legislature and Governor appropriate the funds through legislation. The staff proposal fails to provide reasons as to why CBF should not be created at the onset of the program. We offered a viable and specific proposal (attached), whereby funds could be provided at the initial onset of the Cap and Trade program. We urge you to reconsider our recommendation to ensure that CBF is created at the onset of the program, with a specific percentage of allowances. Or delay the use of offsets into the program for future years when additional compensatory emission reduction programs can be initiated simultaneously from the CBF funds. Should the Governing Board be unwilling to establish a CBF at the onset of the program with a minimum percentage of allowances being set aside, we suggest that the Board not make any attempts (even the most well-intentioned) to add new resolution or regulatory language which could unintentionally hinder efforts to successfully pursue legislative efforts. (CCA1, CCA3, CCA4)

Comment: The proposed regulation fails to fulfill the mandate for community investment. Nowhere in the regulations or even in the staff report did ARB describe a strategy to implement the requirement to direct monetary benefits to disadvantaged communities. AB 32 requires that ARB "ensure that the greenhouse gas emission reduction rules, regulations, programs, mechanisms, and incentives under its jurisdiction, where applicable and to the extent feasible, direct public and private investment toward the most disadvantaged communities in California and provide an opportunity for small businesses, schools, affordable housing associations, and other community institutions to participate in and benefit from statewide efforts to reduce greenhouse gas emissions." In its discussion of the incomplete Health Impact Assessment, ARB notes that it will explore potential uses of revenue generated by the program to improve public health in California. It also notes that distribution of revenues is an issue that deserves further discussion. While the draft regulation does recommend a Community Benefit Fund, none of these recommendations commits ARB to any concrete action that would actually move private and public money into disadvantaged communities. Moreover, the section lacks a clear vision on the mechanism for giving a value to the carbon credits, determining the allocation to the CBF and the best way to direct investments to the communities most impacted by air pollution. (CBE1)

Comment: CARB must include a strategy to implement the requirement to direct monetary benefits to disadvantaged communities. (CBE1)

Comment: We want to thank you for adding the Community Benefit Fund in today's staff modifications, because the San Joaquin Valley will desperately need the assistance to both cope with climate change and achieve local carbon dioxide reductions that will include co-pollutant benefits and improve public health in our region. (FRESNOMINISTRY)

Comment: We would like you to strongly consider how this economic transformation that will get us to greater emissions reductions and will create jobs at the same time, how all of that will factor on the green jobs creation picture. We can make all of these changes. But if we don't ensure that there's equity in the process for low income communities in the process of transforming our economic conditions or our economy so that we're less dependent on fossil fuels, and use more renewable energy sources, we won't have a position of equity in low income communities. We're asking you to use the Community Benefit Fund feature. (CANAACP)

Comment: Integration of the Community Benefit Fund is into the proposal is a good step forward. The adoption of a community benefits fund should not be in lieu of conducting an analysis of localized impact. We recommend no less than 30 percent of total revenues going towards a Community Benefit Fund and that resources go towards the most impacted and disadvantaged communities. (CAEJA)

Comment: ARB should ensure ongoing and consistent investment in health improvement and GHG reduction in disadvantaged communities through the Community Benefit Fund. We appreciate the resolution which calls for a set aside of revenues, initiation of a public process for determining funding priorities. (ALA)

Comment: I want to commend the inclusion of a recommendation for a Community Benefit Fund or something like that, which was vetoed by the Governor in AB 1405. (CPC5)

Comment: ARB should devote auction revenue to a Community Benefit Fund to help finance co-pollutant reductions in disadvantaged areas. (USFLAW)

> **Response:** In Resolution 10-42, the Board directed ARB's Executive Officer to deposit a minimum of 10 percent of annual proceeds generated from the direct auction of allowances into the Air Pollution Control Fund for appropriation by the Governor and Legislature for programs and projects that reduce greenhouse gas emissions, mitigate direct health impacts of climate change, and promote green collar employment opportunities in the most impacted and disadvantaged communities in California.
>
> In Chapter II and Appendix J of the Staff Report, we discuss the use of auction proceeds for a Community Benefit Fund to recognize the community protection goals of AB 32. As stated in Resolution 10-42, the Board agreed with the recommendations of the Economic and Allocation Advisory Committee including financing economic opportunities and environmental improvements in disadvantaged communities. ARB is precluded from establishing a regulatory program for a Community Benefit Fund until and unless authorized to do so by the Legislature and the Governor. However, the Board did direct the Executive Officer to initiate a public process to develop recommendations to the Legislature and Governor on the types of projects and programs to be funded. We encourage participation in the public process, and believe that appropriate recommendations will be developed and proposed to the Legislature and Governor for appropriation in adequate time.

R-4. Comment: We really urge you to increase auction allowances closer in the program rather than later out so there actually are funds in the community benefit funds that your staff is proposing, rather than us waiting around for these funds for many years to come and having them later in the game. (SFMAYOR2)

> **Response:** We recognize the benefits of an auction system. However, under current economic conditions, an early emphasis on an auction system could hamper the ability of California sources to invest in low-carbon technologies. Freely allocating allowances, initially, will also help prevent leakage of GHG

emissions and job losses in California. Therefore, we will gradually transition to a greater amount of auctioning.

R-5. Comment: CARB must develop specific criteria for how the CBF should be used in order to meet AB 32 requirements to ensure low-income communities are not disproportionately impacted and that there are other benefits beyond GHG reductions. CBE recommends including, but not limiting the CBF funding to these types of projects:

- reducing GHGs and co-pollutants in highly impacted communities, including stationary and mobile source pollution;
- non-fossil fuel electricity generating projects in and by local communities;
- green jobs training for low-income residents;
- disaster planning and preparedness, such as flooding, wildfires and other extreme weather events;
- creating community and specific plans to mitigate land use conflicts; reducing heat-island effects with strategies such as tree shade planting and "cool pavements;"
- improving access to mass transit for low-income riders;
- improving training of industry workers and reducing exposure to pollutants;
- supporting local sustainable agriculture;
- water conservation programs including water catchment projects for homes, roadways and buildings, and greywater use;
- improving water quality in low-income communities; and
- improving or creating park space in low-income communities. (CBE1)

Response: As stated in Resolution 10-42, the Board directed the Executive Officer to deposit a minimum of 10 percent of annual proceeds generated from the direct auction of allowances in the Air Pollution Control fund for appropriation by the Legislature to programs and projects that reduce GHG emissions or mitigate direct health impacts of climate change. The Board agreed with several potential uses of allowance value recommended by the Economic and Allocation Advisory Committee, including financing economic opportunities and environmental improvements in disadvantaged communities. In Chapter II and Appendix J of the Staff Report, we discussed several uses for Air Pollution Control Fund proceeds, including the creation of a Community Benefit Fund. Such a fund could be used to promote projects that simultaneously reduce GHGs and co-pollutants, finance adaptation/preparedness for climate change health impacts, create improvements to mass transit and land use planning, facilitate natural resource conservation, and support non-utility energy-efficiency programs. Additionally, we also discussed a Low Carbon Investment Fund to promote projects that support a green technology workforce training program. We will initiate a public process to develop recommendations on the uses of allocation proceeds. We anticipate that the uses for allocation revenue in the Staff Report will be further developed.

R-6. (multiple comments)
Comment: The proposed regulation requires that collected revenues from the auction of transportation sector allowances be used for public purposes. We urge CARB to strongly recommend to the governor and Legislature to use the funds as the State's Economic and Allocations Committee recommended: 75 percent dividends and 25 percent other uses including a Community Benefit Fund. Such an approach would mirror federal legislation introduced by Senators Cantwell and Collins, the CLEAR Act 2. (CPC1)

Comment: I urge CARB to strongly recommend to the governor and legislature to use auction funds as the State's Economic and Allocations Committee recommended: 75 percent dividends and 25 percent other uses including a Community Benefit Fund. (VESSER)

> **Response:** As stated in Resolution 10-42, the Board directed the Executive Officer to deposit a minimum of 10 percent of annual proceeds generated from the direct auction of allowances in the Air Pollution Control fund for appropriation by the Legislature for programs and projects that reduce greenhouse gas emissions or mitigate direct health impacts of climate change. As further stated in Resolution 10-42, the Board agrees with several uses of allowances recommended by the Economic and Allocation Advisory Committee including returning allowance value to households either through lump-sum rebates or other methods identified in the resolution. In the Staff Report, we discussed the creation of a Community Benefit Fund to recognize the community protection goals of AB 32. We will initiate a public process to develop recommendations to the Governor and Legislature on the types of projects and programs to be funded.

Dividends/Rebates/Tax Cuts to Residents/Ratepayers/Electricity Sector Use of Consignment Auction Proceeds

R-7. (multiple comments)
Comment: I support the auctioning of carbon permits to the utilities sector. The government should give 75 percent of the money, as recommended by the EAAC, as a dividend to low- and middle-income residents in the form of a lump sum of money to offset the increase in costs. This would relieve some of the financial burdens of citizens, such as veterans, who need it the most. Please make this a strong recommendation in the Regulations to the Governor and Legislature. (TASSARO)

Comment: I urge you to follow your expert economic panel's recommendation that "The largest share (roughly 75 percent) of allowance value should be returned to California households..." in the form of a dividend check. (LARES)

> **Response:** As stated in Resolution 10-42, we agree with several uses of allowances recommended by the Economic and Allocation Advisory Committee, including the value of lump-sum rebates. We will initiate a public process to

develop recommendations to the Governor and Legislature on the types of projects and programs to be funded.

R-8. Comment: In the electricity sector, the final Regulation should direct utilities to protect ratepayers by returning allowance value directly to residential customers as a rebate check. (HANSON, SONOMAFCC, FORMLETTER01)

Response: The Regulation states that electrical distribution utilities must use allowance value for the benefit of retail ratepayers, consistent with the goals of AB 32. We believe ratepayers could benefit from rebates, customer bill relief, or energy-efficiency programs.

R-9. (multiple comments)
Comment: Providing dividends to every California resident will require some extra logistical and public education work, but California is a pioneering state and California is the place where this type of democratic innovation is most likely to succeed. Please set the example for the rest of the world by introducing substantial dividends as part of the Cap and Trade regulation. I strongly encourage you to take the same approach with electricity and other sectors, and provide these revenues as dividends to consumers as well. (CANFIELD1)

Comment: Direct utilities to protect ratepayers by returning allowance value directly to residential customers as a rebate check. Allowing utilities to use allowance value for a vaguely-defined "ratepayer benefit" gives too much discretion. CARB should require the utilities to consult with local governments and stakeholders, with special attention to those with local GHG reduction goal. Any consumer rebate from utilities should not show up as a line item on electricity bills, shielding consumers from the price signal and discouraging changed behavior. My recommendations follow the EAAC recommendations that "the largest share (roughly 75 percent) of allowance value should be returned to California households" in the form of a dividend check. The remaining 25 percent should be used for a variety of purposes including preventing leakage (a very small percent), investments in renewables and energy efficiency, and a Community Benefit Fund. (CARBONSHARE)

Comment: Some of that money should go to California households to offset costs that no doubt would be passed on to consumers by utilities. This would be a big help in getting people invested in the project. (AMENTA)

Comment: I urge you ensure that auction revenues allocated to electric distribution companies directly benefit ratepayers by directing utilities to return allowance value directly to ratepayers as a rebate check. A per capita dividend to households would be a progressive policy that would benefit low-income households who spend a larger fraction of their income on fuels. (KUNKEL)

Comment: We are concerned that the utility sector will not return the allowance value to ratepayers in the most direct way, and urge CARB to compensate consumers with a dividend. (CPC1)

Comment: Provide residential ratepayers a direct rebate through lump-sum payments. Auctioning allowances and returning a large portion of the auction revenues directly to consumers are essential for ratepayer protection. Equal rebate checks for residential ratepayers (or at least equal within a LDC service area) are essential to ensure basic fairness of the program and to protect low- and middle-income ratepayers from potential increases to electricity prices. CU ardently supports a direct consumer rebate as opposed to an LDC-pass through. We strongly believe that a direct consumer rebate or "lump-sum transfer" should be the only allowable use of these funds. (CONSUMERSUNION)

Comment: Dividends (or tax cuts) should be a majority use of allowance value, not just another use of allowance value comparable to any other. Dividend checks to every California household do help with the costs that will be passed down to consumers, but they also recognize the shared ownership of the commons, and that the first priority is to return the value of this commons back to the people. (VESSER)

Comment: AB 32 requires regulations that your Board approves ensure low income communities are not disproportionately impacted. Without a dividend or rebate, low and middle income citizens will be disproportionately impacted. We encourage you to strongly recommend to the Governor and the Legislature the inclusion of dividends. (CPC4)

Comment: To the extent consumer rebates are offered, similar rebates should be available to consumers of fuels, electricity, and other consumer products. (CCC, MAZOWITA)

Comment: I am in favor of initial maximization leading to 100 percent auction of permits compensating ratepayers with a dividend. (CPC2)

Comment: We do not see dividends as just another use of allowance value, but rather as a structural foundation for a fair and effective policy. (CPC4)

Comment: I recommend a dividend check that would be paid to all residents of California to help redistribute monies that were taken in the process of the Cap and Trade program. (CPC3)

Comment: I urge you to create a structure where 100 percent of the permits are auctioned and most of the revenue is returned to California residents. This is key to ensuring that the system retains the broad support it needs to do its work over time, as well as to help individual residents deal with higher prices on items that have carbon in them. (GLICK)

Comment: AB 32 requires regulations that your board approves "ensure low-income communities are not disproportionately impacted." For this reason, tax cuts do not make sense because they do not help the people most vulnerable to higher energy prices. Without a dividend or rebate, low and middle income citizens will be disproportionately impacted by increased energy prices creating an economic and political obstacle for the smooth implementation of the law. If dividends are included in the first compliance period, they may be used as a feature to sell the program to the public up front. They will build political support for energy efficiency and climate protection over time and demonstrate to the rest of the country that this complex issue can be solved in an equitable fashion. Not including dividends will give the impression that CARB is more concerned with the impact of these Regulations on businesses than on consumers. (CPC1, VESSER)

Comment: Put money back into the hands of the people of California. (KOWALICK)

Comment: Use revenue to lower the budget deficit or return to residents or taxpayers. (DAWID)

Comment: Greenlining recommends that bill rebates be made to low-income households, as suggested by EAAC. This is intended to prevent the percentage reduction in real income for low-income households from being greater than that of other household income groups. Greenlining also recognizes the importance of not creating a disincentive for energy conservation. As a result, Greenlining favors the use of separate cash rebates, rather than simple bill discounts. These transfers should be done in a way that accounts for disproportionate impacts, rather than an equal across the board subsidy for all households. (GREENLINING1)

Comment: We support the proposed Regulation's inclusion of consumer refunds as a use of allowance value. We believe the most direct approach to this is a "lump-sum transfer" which could be implemented through a dividend check. The customer would still receive the carbon price signal on their utility bill, but would receive a rebate check to help buffer them from the regressive impact of increased electricity prices. (CPC1)

Comment: For the utility sector, CARB has proposed a combination of free allowance giveaways and (secondary) auctions. CARB wants the utilities to pass along the subsidy to consumers in a way that encourages conservation. The Economic and Allocations Advisory Committee (EAAC) report did a great job explaining the flaws in the PUC/CEC recommendation to allocate to utilities. The EAAC recognized that providing a rebate through utilities (showing up only as a line item on electricity bills) shields consumers from the price signal and discourages changed behavior. Separating the return of money from the utility bill is critical for sending any price signal at all to residential customers. There is no environmental benefit from keeping people's utility bills low. Therefore, I support the proposed Regulation's inclusion of consumer rebates as a use of allowance value. I believe the most direct approach to this is a "lump-sum transfer" which could be implemented through a dividend check. The customer would still receive the carbon price signal on their utility bill, but would receive a rebate check to help buffer them from the regressive impact of increased electricity prices. (CPC1, CPC4, VESSER)

Comment: Return a large segment of the revenue as a dividend. The forcing should come from technology competing in the market. (DSOUZA)

Comment: In the electricity sector, I am concerned about costs related to administering rebates or funds back to ratepayers and about the utilities' track record in rate reduction and equitable consumer benefit. In this time of budget deficits and economic stress a program design with the least cost to administer would be advisable. The Economic and Allocation Advisory Committee's March 25, 2010, recommendation, which suggests returning 75 percent of allowance value to California ratepayers, may provide an opportunity for lowest cost administration and overhead. It may be worth delaying adoption of this portion of the regulations until further examination of optimal means to reduce consumer economic impacts. (ASMSKINNER)

> **Response:** Per Board Resolution 10-42 we acknowledge the importance of protecting California consumers and that a portion of allocation proceeds should be returned to them. We also agree with the recommended uses of allowances made by the Economic and Allocation Advisory Committee. In Chapter II and Appendix J of the Staff Report, we consider a Per Capita Consumer Rebate Program. A per capita lump sum distribution of the proceeds raised at auction would help consumers avoid negative impacts of higher fuel expenditures while still providing the correct incentives to reduce fossil fuel use. In Board Resolution 10-42, we also refer to the potential of returning allowance value to households through lump-sum rebates. We will initiate a public process to develop recommendations to the Legislature and Governor on the types of projects and programs to be funded by allocation proceeds, during which the potential uses for allowance revenue will be further developed.

Small Business

R-10. (multiple comments)
Comment: Small Business California urges ARB to incorporate explicit recognition of the key role California small businesses will play in achieving California's climate action goals. ARB should include language that explicitly recommends that allowance auction revenue deposited into the air pollution control fund be used to support access to capital mechanisms that will allow businesses to invest in energy efficiency and alternative transportation. While we're pleased to see these programs are now in place in most California utility service areas, there is a need to bridge financing for contractors to be able to afford to wait for payment from these utilities programs, which currently can stretch out 90 to 120 days. We believe the most cost effective way to facilitate this is to provide loan loss reserve funding, lower finance bridging mechanisms, and other financing tools. (SBCA1, SBCA2)

Comment: We are concerned that we won't get sustained investments back into growing a green economy that provides pathways out of poverty and helps our oncoming small businesses. (EBCHR)

> **Response:** We recognize the importance of California's small businesses. In Board Resolution 10-42, we commit to annually evaluate the effects of the regulation on small businesses and low-income households. Additionally, the Board directed the Executive Officer to initiate a public process to develop recommendations to the Legislature and Governor on the types of projects and programs to be funded. We encourage participation during the anticipated public process.

Low-Carbon Investment Fund

R-11. Comment: Hydrogen Energy supports the Board's proposal for a Low-Carbon Investment Fund. Technology is an important element to the AB 32 Scoping Plan and to California's climate change program. A Low-Carbon Investment Fund endowed with these increasing revenues and specifically dedicated to advancing GHG reduction technology would be a shining example of how the cap and trade program could deliver secondary economic and environmental benefits. This is also a tremendous opportunity to showcase California's innovation and high-tech leadership. Hydrogen Energy recommends that the Board specify that revenue from allowance auctions be set-aside annually to fund the Low-Carbon Investment Fund in general, and specifically for Carbon Capture and Storage projects. Having the acknowledged support of the Board will provide future governors and legislative members guidance on how these new funds would best be expended in pursuit of the goals of AB 32. (HECA)

> **Response:** Thank you for your support. We will initiate a public process to develop recommendations to the Legislature and Governor on the types of projects and programs to be funded and encourage participation during the public process.

R-12. Comment: Some part of allowance value should be used to develop and promote low carbon-emitting industrial processes, as well as other societal benefits such as assistance transitioning for workers and small businesses. (WALTERS, UCS1, WALTERS)

> **Response:** As stated in Resolution 10-42, the Board directed the Executive Officer to deposit a minimum of 10 percent of annual proceeds generated from the direct auction of allowances in the Air Pollution Control fund for appropriation by the Legislature for programs and projects that reduce greenhouse gas emissions or mitigate direct health impacts of climate change. As further stated in Resolution 10-42, the Board agrees with several uses of allowances recommended by the Economic and Allocation Advisory Committee. In Chapter II and Appendix J of the Staff Report, we discussed several uses for Air Pollution Control Fund proceeds, including the creation of a Community Benefit Fund.

Such a fund could be used to promote projects that simultaneously reduce GHGs and co-pollutants, finance adaptation/preparedness for climate change health impacts, create improvements to mass transit and land use planning, facilitate natural resource conservation, and support non-utility energy-efficiency programs. Additionally, we also discussed a Low Carbon Investment Fund to promote projects that support a green technology workforce training program. We will initiate a public process to develop recommendations on the uses of allocation proceeds. We anticipate that the uses for allocation revenue in the Staff Report will be further developed.

Renewables and Energy-Efficiency Projects

R-13. Comment: Revenue generated from the sale of allowances should be allocated to natural gas local distribution companies (LDC) for the benefit of ratepayers to fund customer energy efficiency and similar programs. The revenue allocated to each LDC should be determined by using the same procedure used for allocating allowances. To the extent the LDCs further the goals of AB 32 through their energy efficiency programs, allowance value could be used to advance and support such programs. Under the proposed Regulation, natural gas LDCs are expected to procure allowances and pass on the cost of such allowances to their customers. Southwest believes that the per-capita reductions in natural gas consumption should be recognized as credits (or should at least be a factor) in the formula used to allocate initial allowances and calculate allowance reductions over time to support a more generous allocation of allowances that might otherwise be based on current consumption rates. (SWGASCORP)

Response: In Chapter II of the Staff Report, we describe an alternative under consideration in which allowances associated with emissions from dispersed natural gas combustion would be auctioned and the allowance value returned to customers through action by the Legislature. This alternative will be discussed during the public process to develop recommendations to the Governor and Legislature on the uses of allocation proceeds.

R-14. (multiple comments)
Comment: Funds could be used for programs to reduce energy use in buildings and boost public transit options. (TERSOL)

Comment: Proceeds from auctions should be reinvested into localized community energy projects and programs. "Solar Done Right" is such a group. Their focus is on building solar capacity into the existing, built environment that is already grid tied, rather than large centralized projects taking up valuable agricultural or park lands needing long transmission lines to then be laid. (EICHELBERGER)

Comment: Apply auction revenues toward funding research and development into low carbon technologies, including Carbon Capture and Storage (CCS). Auction revenues should fund investments in CCS technologies. For CCS to move rapidly toward commercial scale and contribute a measurable impact on emissions reductions, further incentives are required to encourage research and development and deployment of CCS technologies. We recommend that allowance auction revenues received by CARB and the California energy utilities be used in part to provide grants and other opportunities supporting investments in emerging clean technologies, including bio-industrial technologies that reduce GHG emissions and promote energy security. Cap-and-trade revenues should invest in California's low carbon energy future by accelerating research, development, and deployment of carbon capture and other innovative technologies required to meet the global challenge of emission reductions. Using auction revenues to fund research and development will attract significant high quality job opportunities to California. (CODEXIS)

Comment: We suggest that revenues from the cap and trade program be used directly for the support of renewable energy projects that are additional and beyond business as usual. (PCAPCD)

Comment: Re-invest money in making homes and businesses more energy efficient, increasing public transit options, and developing wind and solar projects in California. (DUTTON, FUTRELL)

Comment: I believe permits need to be offered at a cost, to help fund energy efficiency and for developing alternative energy sources. (SUSTAINDESIGN)

> **Response:** We agree that auction proceeds could be used to support energy-efficiency programs and projects that identify zero- or low-GHG technologies, reduce energy use in buildings, boost public transit options, and similar uses that align with the goals of AB 32. We recommend potential uses of auction proceeds in Chapter II and Appendix J of the Staff Report under a Community Benefit Fund. We will initiate a public process to develop recommendations to the Governor and Legislature on the types of projects and program to be funded. We encourage participation in the prospective public process, and would be a good opportunity to further discuss the specific use of funds within a Community Benefit Fund.

R-15. Comment: Auctions are unknown and depend upon many variables. The unpredictability of auctions is not a positive point for conducting business in California. If an auction is instituted, the auction proceeds should go back into advancing energy efficiency. (NAIMA)

> **Response:** We agree that auction proceeds should go toward advancing energy efficiency and similar uses that further the goals of AB 32.

R-16. Comment: The investment of auction proceeds should facilitate near-term shifts to clean energy resources, applications, and technologies in order to save consumers money, reduce emissions, enhance energy security, and create jobs in clean energy sectors. (BCFSE)

> **Response:** We agree and recommend similar uses of revenues in Chapter II and Appendix J of the Staff Report under a Community Benefit Fund and Low Carbon Investment Fund.

Transportation / Support Local Government

R-17. Comment: CARB should include in any Cap and Trade regulation it adopts language that explicitly recommends that allowance auction revenue deposited into the Air Pollution Control Fund be used to support local government programs and initiatives. The purpose is to direct the Governor's office and the Legislature to appropriate allowance auction revenue to local governments to facilitate a community benefit fund, for example. (LGSEC)

> **Response:** In Chapter II of the Staff Report, and in Appendix J, we recommend using auction proceeds for a Community Benefit Fund to recognize the community protection goals of AB 32. The Board directed the Executive Officer to initiate a public process to develop recommendations to the Legislature and Governor on the types of projects and programs to be funded, and we encourage the commenter to participate in the public process.

R-18. (multiple comments)
Comment: We urge you to recommend an investment of at least 10 percent of market-based revenues into funding transit expansion and similar transportation projects to reduce GHG emissions. This will advance GHG emissions reductions in the State as it shifts travel modes to reduce emissions, and will at the same time provide cleaner and more efficient mobility to California's citizens. (CATRANSASSOC1)

Comment: If transportation fuels are included in cap and trade, allowance value associated with the sale of gasoline and diesel should flow back to fuel customers. Under the proposed Regulations, electricity consumers will see a significant proportion of the costs of regulation offset over the life of the program via allowance allocation to local distribution companies for the purpose of consumer protection (see section 95870(c)). In contrast, commercial and light-duty vehicle transportation consumers will pay the full cost of carbon associated with transportation fuels from the time those emissions come under the emission cap starting in 2015. The inclusion of transportation fuels in the cap could increase the consumer cost of these products by nearly $0.20 per gallon (at $20 per ton CO_2E). The Regulations should direct the bulk of the allowance value attributable to transportation consumer emissions towards easing the cost burden on those consumers. Compensation of transportation consumers could take the form of direct rebates, offsets of existing taxes, incentives to promote the safe and efficient use of transportation fuel, or infrastructure improvements to increase transportation system efficiency. Transportation consumer compensation should be proportionate to compensation received by other energy consumer groups (e.g. electricity consumers). (CONOCO)

Comment: Proceeds from the sale of allowances should be available to such entities as transit districts and local governments, which can implement on-the-ground measures and operations that have significant GHG emission reduction benefits. (ASMDICKENSON)

Comment: The City of San Francisco urges the Board to incorporate the following recommendations, both in allocating allowances and in deciding how to use revenues from the sale of allowances by:

1. Recognizing the historically low emissions of the San Francisco Public Utilities Commission electric system and allocating allowances to the electric sector.
2. We're going to need funds to increase transportation infrastructure. (SFMAYOR2)

Comment: The City urges the Board to create a dedicated funding mechanism for public transportation infrastructure and planning, and to channel increased funding to cities that have demonstrated leadership on GHG reductions and could expand these efforts to mutually benefit both cities' and the State's climate action strategies. The proposed Cap and Trade system has the potential to increase the cost of fuel at the as fuel producers offset the cost of emission allowances by increasing the cost of fuel. We therefore recommend that ARB include explicit language in the Air Pollution Control Fund to decrease the impacts of rising fuel costs on public transportation providers and dedicate Cap and Trade allowances to a transportation investment program. The program would invest in transportation infrastructure, planning resources to develop and implement regional and local land use and transportation plans focused on implementing the GHG reduction goals in AB 32 and the planning mandates of SB 375, transportation demand management programs. Current State transportation funding programs that come from the sales tax on gasoline should be set up to dedicate any increases from this program to transportation infrastructure investments that limit GHGs. Also, transit service providers should be expected and allowed to increase energy consumption. ARB should also give low GHG-emitting public transit agencies credit for the services they provide, such that agencies which have already made proactive investments to reduce emissions do not find themselves unnecessarily burdened by the rising energy costs of the proposed Cap and Trade program. We further recommend that ARB create a forum for further input from and discussion with transit agencies and transportation planners around the State to mitigate expected impacts, and devote funds to job training and disadvantaged communities. ARB's consideration for utilizing a Low-Carbon Investment Fund for workforce development can be further strengthened by adopting a "green pathways out of poverty" strategy. Acknowledging the communities that have historically carried the brunt of environmental injustices in our State by supporting their growth in the burgeoning green economy would strengthen the impact of a Cap and Trade plan, and could add to the universal support of such a plan. Finally, "Job Training" and "Disadvantaged Communities" are listed as two separate opportunities for public investment of the Cap and Trade allowances, yet there is a clear opportunity and need for these types of investments to be strategically coordinated. While many higher learning institutions offer access to jobs in the green workforce, there is still a disproportionate number of young adults from undeserved or disadvantaged communities who do not have access to these resources; preventing access to quality green jobs. The Cap and Trade allowance investment could act as a social-economic equalizer in the aspect by ensuring high level training. (SFMAYOR1)

Comment: We would like to stress the opportunity that the cap and trade regulation presents to create a sustainable source of substantial funding for GHG reduction technologies, specifically in the transportation sector. We support CARB's proposal to require 100 percent auctioning of allowances in the transportation fuels sector once implemented in Phase II and III. However, we urge CARB to ensure that the substantial revenue stream created by this process is invested back into the transportation sector and is utilized for GHG reduction measures. These measures could include funding for local governments to implement SB 375 and vehicle miles traveled reduction strategies, incentive funding for emerging clean vehicle technology, subsidies for alternative fuel infrastructure, and many others. While EIN recognizes that the California Legislature is ultimately responsible for the allocation of funds, CARB should include stronger language and guidelines in the cap and trade regulation for the use of allowance auction revenue. (EIN)

> **Response:** We agree with many of the points raised in the above comments. We address these topics in the Staff Report and 15-day changes to the regulation. As stated in Resolution 10-42, the board directed the Executive Officer to deposit a minimum of 10 percent of annual proceeds generated from the direct auction of allowances in the Air Pollution Control fund for appropriation by the Legislature to programs and projects that reduce GHG emissions or mitigate direct health impacts of climate change.
>
> We agree with the potential uses of allowance value recommended by the Economic and Allocation Advisory Committee, including financing economic opportunities and environmental improvements in disadvantaged communities. In Chapter II of the Staff Report, we recommend the creation of a Community Benefit Fund as one of several uses for the proceeds in the Air Pollution Control Fund. A Community Benefit Fund could be used to promote projects that create improvements to mass transit and land use planning. As noted in the comments, we also describe a Low Carbon Investment Fund which could promote projects that support a green technology workforce training program. We will initiate a public process to develop recommendations on the uses of allocation proceeds. We anticipate that through the public process, the recommended uses for allocation proceeds in the Staff Report will be further developed.
>
> We will also annually evaluate the effects of the regulation on small businesses and low-income households; as well as the treatment of transportation fuels in the cap-and-trade program, including the effects of allowance distribution to different sectors within the transportation sector, and commitment to propose any necessary changes to the regulation before the start of the second compliance period in 2015.

Natural Community Conservation Plans (NCCP)

R-19. Comment: We ask that ARB incorporate in the regulation specific language identifying ecosystem adaptation, including Natural Community Conservation Plans (NCCP), as a recommended use for allowance value. NCCPs are prepared under State law by local jurisdictions and special districts, in partnership with stakeholders and State and federal wildlife agencies. Use of some of Cap and Trade program allowance value will be leveraged greatly by developer funds and public conservation funds. (CAHCPCOALITION)

> **Response:** We encourage the commenter to participate in the public process to develop recommendations on the use of allowance revenue.

Agriculture

R-20. (multiple comments)
Comment: We strongly oppose staff's proposal to return the value on a per capita basis because it does not adequately compensate the increased energy costs to consumers. The agriculture industry will incur substantial increases in energy costs due to the program, but the rebate will be very minimal based on the amount of use. If any rebate does occur under the program for the costs of the program, the rebate should be comparable to the costs incurred. (AGCOALITION)

Comment: Include in the final cap and trade regulation CARE's recommendations to the legislature on how allowance revenue can help meet the State's climate change goals, including allocating a portion of allowance revenue to support climate change mitigation and adaptation activities in agriculture. (CACAN1, CACAN2)

Comment: Should allowances be auctioned, Ag Council requests that some of that relief be provided to food and agriculture. These funds could help offset costs incurred by rate increases and investments at the plant, but potentially be invested in research and development in existing and future technologies. (ACC3)

Comment: CARB should include language specifying that agricultural and food processing sectors should be considered as rate-payers and some of those funds should be directed back toward the industry accordingly. (ACC3)

Comment: We cannot rely entirely on future carbon markets to achieve GHG emission reductions in agriculture. The marketplace lacks adequate funding for research to understand opportunities within farming systems to achieve GHG emission reductions. Translating research findings into real opportunities for California agriculture to provide voluntary GHG reductions requires technical assistance. In some cases, when transition costs may be high, financial incentives for farmers and ranchers are essential. Allowance revenue can turn research into opportunities for agricultural activities to help meet the State's GHG emissions targets and help farmers and ranchers adapt to climate change. (CACAN1, CACAN2)

> **Response:** In Chapter II of the Staff Report, we recommend that a portion of total allowance value be directed toward public investments in the energy innovation goals of AB 32. This use of auction proceeds could be structured as a competitive grant program administered by ARB or another entity. Project types could include research, development, and demonstration projects in zero- or low-GHG technologies for agricultural activities.

Direct Allocations of California GHG Allowances

R-21. Comment: CARB should consider whether revenues from an auction could be used to replace a fee system. (LADWP1)

> **Response:** It is not clear what fee system the commenter is referring to. However, if the commenter is referring to the AB 32 Cost of Implementation Fee Regulation (Fee Regulation), we do not agree that the Fee Regulation should be replaced by the cap-and-trade regulation. The appropriation of auction proceeds and fees collected through the Fee Regulation are approved by the Governor and Legislature.

R-22. (multiple comments)
Comment: We ask CARB to include explicit language in the regulation identifying recommended uses for allowance value. The Economic Allocation Advisory Committee (EAAC) outlines a number of critical investments that should be acknowledged, including ecosystem adaptation and land use and transportation, which would be consistent with the broader goals of AB 32. It is critical to dedicate funding to help our natural systems adapt to climate change. Investment of allowance value for this purpose will protect the vital carbon sequestration and climate regulation functions of our natural lands and the critical role they can play in buffering our communities from the worst impacts of climate change. Allowance value investments and compensation should be dedicated to all natural systems in California for mitigation and adaptation purposes, including its forests, grasslands, working landscapes, coastal areas, watersheds, and deserts to protect and promote their vitality and diversity and the many benefits that they provide to Californians and the economy. These benefits include carbon sequestration and climate regulation, clean drinking water, provision of food and jobs, air quality protection, flood control, wildlife habitat, crop pollination, recreation and timber, among other things. The public cannot afford to lose these benefits, and the State has an opportunity to ensure their long term persistence by dedicating a significant portion of allowance value to these resources. It is also critical for CARB to recommend investment of allowance value in land use and transportation strategies that reduce GHG emissions from transportation and infrastructure sources while also protecting the carbon mitigation function of California's natural systems. By integrating conservation and climate change goals into land use and infrastructure planning, the state can optimize GHG reductions across sectors and preserve our natural systems

which are the foundation of a healthy and prosperous California. Much of the authority to make these changes rests with local governments, but severe funding shortages present considerable barriers to implementing the necessary actions. The EAAC report recognizes the need to fund local governments and regional agencies for land use and transportation related reductions that promote sustainable communities and we urge CARB to acknowledge this in the regulation as well. While we recognize that CARB may not have full authority to determine the ultimate use of allowance value, we think it is critical to acknowledge in the regulation how it should be invested. The EAAC report provides a strong basis for identifying the kinds of investments that the State should make, including ecosystem based adaptation and mitigation and land use and transportation, to help fulfill its climate policy goals. We urge CARB to include these recommendations in its regulations. (NC5)

Comment: A significant portion of allowance revenue should be used to fund research, and development, and commercialization of biofuels and bio-based products that demonstrate a GHG reduction compared to the current alternative. (ERICKSON)

Comment: CLFP opposes using auction revenue to fund any of programs that do not directly relate to reducing long-term greenhouse gas emissions. Auction revenue should be dedicated first to transition assistance to reduce or prevent losses due to leakage related to higher prices and lower profits or to offset costs resulting from modification or retrofit of existing operations or the purchase of new equipment to reduce onsite GHG emissions necessary in meeting compliance goals. (CALFP1)

Comment: We recommend returning a significant portion of the allowance value to the people of California. Although we expect the State to help finance investments designed to achieve low-cost emissions reductions, help adapt to climate impacts, help disadvantaged communities, and provide job training to acquire the skill sets needed for the new technologies and industries, the State should have flexibility in using the auction revenue. (UCS3)

Comment: We understand ARB may not have the authority to direct potential cap and trade revenues in the proposed regulation. However, we strongly support the EAAC recommendation to devote a significant share of allowance value toward financing of public and private investments. The investments to consider include those oriented toward achieving low-cost emissions reductions (both directly and through investments in cleantech research and development), adaptation to climate impacts, environmental remediation, improvements to disadvantaged communities, and job training. (CARELEAF)

Comment: Allowances should be auctioned, with the money used for clean energy, green jobs, public transit, and low-income consumers. (STEWARTJ)

Comment: Money should be used for clean energy, green jobs, public transit, and low-income consumers. (FORMLETTER10)

Comment: The use of GHG allowances can play an important role in meeting California's ambitious 2020 GHG goals and set us on the path to meet ambitious long-term 2050 GHG goals. Industrial sector allowances could support further action to meet AB 32's GHG reduction goals and associated environmental and economic benefits. For instance, the Economic and Technology Advancement Advisory Committee (ETAAC) Advanced Technology Development sub-group report recommended options for using the value of GHG allowances to help end-users and producers transition California to a cleaner and more efficient economy. These options can help both small businesses as well as large GHG intensive producers. (ICCT1)

Comment: Auction revenues from all sectors should be used for comparable purposes. (CCC, MAZOWITA)

Comment: The proposed approach for using auction proceeds should be better defined. (SOLARTURBINES1)

Comment: We ask the CARB to include explicit language in the regulation identifying recommended uses for allowance value. Allowance value investments and compensation should be dedicated to all natural systems in California for both mitigation and adaptation purposes, including its forests, grasslands, working landscapes, coastal areas, watersheds, and deserts to protect and promote their vitality and diversity and the many benefits that they provide to Californians and the economy. It is also critical for CARB to recommend investment of allowance value in land use and transportation strategies that reduce GHG emissions from transportation and infrastructure sources while also protecting the carbon mitigation function of California's natural systems. (NC3)

> **Response:** As stated in Resolution 10-42, the Board directed the Executive Officer to deposit a minimum of 10 percent of annual proceeds generated from the direct auction of allowances in the Air Pollution Control fund for appropriation by the Legislature to programs and projects that reduce GHG emissions or mitigate direct health impacts of climate change. We agree with the potential uses of allowance value recommended by the Economic and Allocation Advisory Committee, including financing economic opportunities and environmental improvements in disadvantaged communities. In Chapter II and Appendix J of the Staff Report, we discuss several uses for Air Pollution Control Fund proceeds, including the creation of a Community Benefit Fund. Such a fund could be used to promote projects that simultaneously reduce GHGs and co-pollutants, finance adaptation/preparedness for climate change health impacts, create improvements to mass transit and land use planning, facilitate natural resource conservation, and support non-utility energy-efficiency programs. Additionally, we also discussed a Low Carbon Investment Fund to promote projects that support a green technology workforce training program. We will initiate a public process to develop recommendations on the uses of allocation proceeds. We anticipate that the uses for allocation revenue in the Staff Report will be further developed.

R-23. Comment: Proceeds from the Advance Auction and all remaining allowances not allocated for uses specified in sections 95870(a)-(e) will be designated for sale at auction. The Proposed Regulation designates funds from the sale of these allowance pools will be deposited into the Air Pollution Control Fund and will be available for appropriation by the Legislature for the purposes designated in California Health and Safety Code sections 38500 et seq. During the rulemaking to consider adoption of proposed AB 32 Cost of Implementation Fee Regulations, staff stated that "As the state's Cap and Trade program becomes more developed funding the administrative costs associated with AB 32 will be considered if appropriate." At the time, ARB disagreed that the regulation itself should clarify that the fee proposed therein would only be an interim funding measure as it was premature to assume that funding would come from a cap and trade program, or any another source. We recommend that ARB recognize this mode of funding administrative costs. Modify sections 95870(b)(2) and (f) as follows:

(2) The proceeds from the sale of these allowances will be deposited into the Air Pollution Control Fund and will be available for appropriation by the Legislature for ~~the~~ <u>funding the cost of implementation of AB 32 and other</u> purposes designated in California Health and Safety Code sections 38500 et seq.

(f) Auction Proceeds for AB 32 Statutory Objectives. All remaining allowances not allocated for uses specified in sections 95870(a)-(e) will be designated for sale at auction. The proceeds from the sale of these allowances will be deposited into the Air Pollution Control Fund and will be available for appropriation by the Legislature for ~~the~~ <u>funding the cost of implementation of AB 32 and other</u> purposes designated in California Health and Safety Code sections 38500 et seq. (SEMPRA1)

> **Response:** We do not agree with the commenter's recommendation. The AB 32 Cost of Implementation Fee Regulation is authorized and appropriated by the Governor and Legislature to (1) pay for the cost of the State's AB 32 program as appropriated annually by the Legislature, and (2) repay loans that were used to fund the AB 32 program during the first few years of implementation.

Use of Consignment Auction Proceeds

R-24. (multiple comments)
Comment: We support the requirement that all utility sector auction revenues be used for the benefit of ratepayers and to meet the goals of AB 32. If this benefit takes the form of rebates, the rebates should be limited to residential ratepayers and include all residential electricity customers within the utility's distribution service territory. If the benefit takes the form of clean energy investments, these investments should be made in accordance with the goals laid out in AB 32. We are concerned that the language in the draft regulations requiring that auction revenues simply be spent for the benefit of ratepayers "consistent with the goals of AB 32," affords utilities insufficient direction and puts allowance value at risk of predominately subsidizing business as usual (aka

investments that are already required under existing law). While we appreciate the oversight that the CPUC and local governing boards of the POUs can provide, we encourage CARB to provide additional guidance in the regulations to give utilities a better sense of where they should direct allowance value, and to ensure uniformity of purpose among the state's many utilities. We ask CARB to give clear guidance to the utilities, as well as the CPUC and local governing boards, that any allowance values not rebated to customers but spent on clean energy programs, should be limited to the following uses, described in more detail below. Utilities that use allowance values for clean energy investments should be required to first invest in cost-effective energy efficiency. California's loading order establishes all cost-effective energy efficiency as our first priority procurement resource. Under AB 32, cost-effectiveness is defined relative to the cost of achieving the emission reductions necessary to meet AB 32's goal of returning to 1990 emissions level by 2020. As long as energy efficiency can provide emission reductions at lower cost than other emission reduction strategies, it should be considered cost-effective. Significant energy efficiency potential remains in utility service territories that may not be cost-effective under a utility procurement framework, but is cost-effective under AB 32's framework; i.e., compared to other available emission reduction strategies that must be utilized to achieve our 2020 goal. To comply with AB 32's directive to achieve emission reductions at least cost, and to provide additional bill relief to utility customers, CARB should require utilities that receive allowance value to capture additional energy efficiency savings. (UCS1, WALTERS, LUDLOW, KUSTIN10, EBERHARD)

Comment: CARB has proposed a combination of free allowance giveaways and (secondary) auctions. The allowances are given for free to utilities that deliver electricity. Investor-owned utilities would sell the allowances to the generators when they buy electricity from them. Publicly-owned utilities that produce their own generation would need the allowances themselves. After the allowances are "monetized," the utilities are to use the billions of dollars in allowance value "to reduce the costs of AB 32 policies on their ratepayers," for "ratepayer benefit" (section 95892) and "for protection of electricity customers and for other AB 32 purposes." In the final regulation, CARB must provide a more specific definition of "ratepayer benefit" to utilities. (CPC1)

Comment: To strengthen our confidence that the consignment auction will support AB 32 goals, the uses of allowance value should be made more explicit, as should the within-sector allocation. (EDF1)

> **Response:** We modified section 95892 of the regulation to include conditions and reporting requirements that limit the use of auction revenue (utilities' monetized allowance value). CPUC currently regulates the use of ratepayer funds and utility shareholder funds for energy efficiency and renewable energy. Furthermore, although the rate structure is complex, we believe electricity consumers need to see a price signal that the cost of GHG emissions creates in the price of electricity. CPUC remains committed to ensure that allowance value is used for the purposes listed in these comments. As directed by the Board in

Resolution 10-42, we will continue to work with the CPUC and POUs to help monitor and provide input on this topic.

R-25. Comment: Section 95892(d)(3) limits the use of auction proceeds obtained by an electrical distribution utility to those purposes that benefit retail ratepayers. This is vague and unenforceable. What is an example of a use of auction proceeds that could not be characterized as ultimately "for the benefit of retail ratepayers"? Also, what are the consequences if auction proceeds are used inappropriately? (CAPCOA1, CAPCOA2)

> **Response:** Section 95892 details the requirements for the use of auction proceeds. Publicly owned utilities are subject to the oversight of their governing board and IOUs are subject to the oversight of the CPUC. Both utilities must also meet the requirements listed in sections 95892(d) and (e). The oversight of the respective governing boards and the requirements in the regulation will provide flexibility for utilities to best meet the needs of their individual ratepayers. To ensure that utilities are using auction proceeds appropriately, they will be required to submit annual reports to ARB no later than June 30, 2013, and each subsequent year.

R-26. Comment: NCPA is supportive of the key principles on which the preliminary consensus recommendation is based, covering the distribution utilities cost burden, recognition of early investments in renewable energy and cumulative energy efficiency. We support this recommendation as long as there are still 97.7 MMT minimum allocation to the utilities, that the allowances are freely allocated to the utilities, and that the value is given to the utilities to be used for the benefit of their rate payers for AB 32 related programs. (NCPA2)

> **Response:** We agree and kept the value of 97.7 million metric tons (MMT) in calculating the allowance allocation to the electrical distribution utilities.

R-27. Comment: We support the proposal to allocate allowances to utilities for the benefit of our customers. We are generally supportive of the approach using the cost burden approach found in Attachment E. We are concerned about the language in the regulation that is only applicable to IOUs and restricts the way in which we can return auction revenue to our customers. This could lead to large discrepancies in how GHG costs are returned to IOU versus POU customers. We recommend that ARB offer IOUs the ability to work with the PUC on how to best return this allowance value for our customer's benefit. (PGE1, PGE2)

> **Response:** We believe that the regulation provides an appropriate approach to allow the return of auction value to ratepayers. The regulation allows flexibility for utilities to choose the method of revenue disbursement. We believe that IOUs have the ability to work with the CPUC to determine the best way to distribute the funds to their respective ratepayers under the current regulatory language.

R-28. Comment: LADWP supports the administrative allocation of allowances to the electric sector and appreciates that ARB recognizes that electricity distribution utilities are best situated to utilize allowance value for their ratepayers, and recognizes the considerable investment required to reduce emissions within the sector. LADWP supports the policy to allocate allowances to distribution utilities to 1) support policies and programs that are reducing GHG emissions from the electricity sector, and 2) ensure that electricity ratepayers do not experience sudden increases in their electricity bills associated with the pricing of carbon emissions in the Cap and trade program. (LADWP1)

> **Response:** Thank you for your support.

Renewable Electricity

R-29. Comment: If utilities are allowed to use allowance value to invest in renewable energy resources, CARB should establish general principles for such investments in accordance with the goals laid out in AB 32. New renewable projects that provide health and job benefits to Californians should be prioritized. For instance, local distributed generation, which typically does not require new transmission capacity and may provide jobs closer to load centers, should be prioritized. All investments using allowance value to procure renewable energy should be limited to projects that service the customers covered by the cap and trade program, in order to maximize the environmental and health co-benefits for those customers. Renewable energy investments using allowance value should not count towards any cost cap that is established to limit the costs of achieving renewable energy procurement requirements that exist in law. (KUSTIN10, UCS1, LUDLOW, WALTERS, EBERHARD)

> **Response:** The CPUC and POUs will determine the best way to meet the goals of AB 32 for their ratepayers. The regulation provides flexibility to include recognition of investments in renewable energy as one of options they can pursue. The regulation requires that allowance value be used to benefit the ratepayers and requires utilities to submit annual reports to show how the auction revenue is being used. This will help to ensure that auction revenue is spent for the ratepayer benefit. We are working closely with CPUC staff in this regard and are following the CPUC proceeding (11-03-012), which will address the use of auction revenue.

Energy Efficiency

R-30. (multiple comments)
Comment: Utilities should be required to first use allowance value to invest in cost-effective energy efficiency. California's loading order establishes all cost-effective energy efficiency as utilities' first priority procurement resource. In that context, cost-effective is defined as a ratio of the total system-wide benefits from saving energy through efficiency measures relative to the total system-wide costs of achieving the savings (the Public Utilities Commission employs the Total Resource Cost (TRC) test to

make this calculation). As long as the benefits exceed the costs (TRC >1), an efficiency program is deemed cost-effective. However, under AB 32, cost-effective is defined relative to the cost of achieving the emission reductions necessary to meet AB 32's goal of returning to 1990 emissions level by 2020. As long as energy efficiency can provide emission reductions at lower cost than other emission reduction strategies, it should be considered cost-effective. Significant energy efficiency potential remains in utility service territories that may not be considered by the PUC to be cost-effective under a utility procurement framework, but is cost-effective when compared with other abatement measures available to meet the goals of AB 32. To comply with the AB 32 directive to achieve emission reductions at least cost, and to provide additional bill relief to utility customers, CARB should require utilities that receive allowance value to capture additional energy efficiency savings. (KUSTIN10, EBERHARD)

Comment: We urge you to approve California's landmark greenhouse gas cap and trade program and tighten the regulation language to ensure that auction revenue in the electricity sector is used for cost-effective energy efficiency programs that will reduce emissions while also reducing Californians' energy bills. (FORMLETTER04)

Comment: Promote investment in cost-effective energy efficiency by requiring Utilities that use allowance values for clean energy investments to first invest in cost-effective energy efficiency. (VARON)

Comment: The regulation states that money from the auction and electricity sector should be used for the benefit of customers, but it doesn't take the next step and say to help customers reduce their bills by investing in cost effective energy efficiency to help businesses reduce their electricity bills. We want to make sure that that is clear as the PUC is moving forward. Also in the allocation, we want to make sure that we're going beyond existing energy efficiency and getting even more. (NRDC2, CAEEIC)

Comment: It's very important for oversight to be established by either the PUC or ARB to make sure that funds generated are spent on appropriate GHG reducing measures, such as efficiency. Given the free allowance allocation, we think that investment in mitigation is critical, not in windfalls to any participants. (CAEEIC)

Comment: Provide clearer guidance to utilities on the use of allowance value in the electricity sector. We believe that the value of allowances should be used for cost effective energy efficiency programs that help Californians lower their energy bills. (ENVENTREP1, ENVENTREP2)

Comment: We are in favor of use of trading proceeds to fund important energy efficiency and renewable energy programs. (CPC2)

> **Response:** We modified the regulation to address concerns about the use of auction proceeds in section 95892. Utilities are required to provide annual reports to ARB for review. This will allow ARB to enforce the regulation and make sure that auction revenue is spent according to the requirements in section

95892. Oversight of the CPUC and respective governing boards and the requirements in the regulation will provide flexibility for utilities to best meet the needs of their individual ratepayers, including investments in renewable energy.

R-31. Comment: Section 95892(a)(3) states that auction proceeds by an electrical distribution utility shall only be used for the exclusive benefit of retail ratepayers. Hydrogen Energy recommends that the concept of "ratepayer benefit" include assistance in the purchase of advanced near-zero carbon electricity, such as that produced at a power plant employing CCS. Though California is a leader and the first state to adopt an economy-wide carbon reduction program, others are sure to follow its lead in putting a price on carbon. This change in the basic economic structure of electrical generation creates a financial liability to those utilities that continue to purchase higher-carbon electricity. Therefore, purchasing near-zero carbon electricity has a direct benefit to a utility's ratepayers and should be eligible under the provisions of section 95892(a)(3) and the Board should require that a portion of these revenues be dedicated to offset ratepayer costs associated with CCS power purchases. Hydrogen Energy recommends that specific language be placed in either the Regulation or adopting Resolution allowing acquiring utilities to use a portion of their consigned auction revenues to reduce the costs associated with near-zero electrical generation. This policy element will provide for revenues to promote cleaner, more advanced technology in this major emissions sector without the need to alter the distribution of allowances as outlined in the Regulation. This guidance will also provide the CPUC or POUs' Governing Boards the ability to approve such actions. (HECA)

Response: The regulation requires that auction revenues be used for the ratepayer benefit. If a technology can be shown to be cost effective at reducing GHG emissions, then it may be feasible for utilities to use it. It may have a relative value for some ratepayers, but may be more costly for others as an emerging technology. As a result, it will be important that utilities work with the CPUC and local governing boards to determine what is best for their ratepayers.

R-32. Comment: Both in allocating allowances and in deciding how to use revenues from the sale of allowances, the City urges the Board to channel increased funding to cities that have demonstrated leadership on greenhouse gas reductions and could thereby further expand their efforts to mutually benefit both local and State climate action strategies. This should be done by recognizing the historically low emissions of the San Francisco Public Utilities Commission electric system and allocating allowances to the electric sector. (SFMAYOR2)

Response: The regulation explains the consensus allocation scheme for electricity providers in section 95892. Table 9-3 shows the allowance allocation for San Francisco. Allocated allowances must be consigned to auction, and the proceeds used to benefit ratepayers.

R-33. Comment: To strengthen our confidence that the consignment auction will support AB 32 goals, the uses of allowance value should be made more explicit, as should the within-sector allocation. (EDF1)

> **Response:** This information can be found in Table 9-3 in section 95892 of the regulation.

R-34. Comment: The immediate deployment of existing clean energy technologies such as renewable energy and energy efficiency will reduce greenhouse gas emissions and help mitigate consumer impacts. In this regard, the Council supports the proposed structure in the draft regulations where utilities that are provided allowances must use them for customer benefit consistent with the goals of AB 32. BCSE supports flexibility for utilities as they make decisions about how best to balance the substantial investments needed to meet the renewables and energy efficiency goals while participating in a Cap and trade program. (BCFSE)

> **Response:** Thank you for your support.

Miscellaneous

R-35. Comment: POUs are governed by their locally electric or appointed bodies. The required reports would be appropriately prepared and submitted to these local governing bodies for approval. The Utilities suggest that, once approved, each POU covered entity would then submit a copy of the approved report to CARB. The Utilities understand that CARB did not intend for these reports to be used for enforcement actions, thus the Utilities offer the following additions to ease in this clarification. Modify section 95892(e) as follows:

> *(e)* Reporting on the Use of Auction Proceeds. Following approval pursuant to 95892(d)(1) or 95892(d)(2), and ~~N~~no later than June 30, 2013, and each calendar year thereafter, each electrical distribution utility shall submit a report to the Executive Officer describing the disposition of any auction proceeds received in the prior calendar year. The Executive Officer shall use these reports for informational purposes only. This report shall include:
>
> > (1) The monetary value of auction proceeds received by the electrical distribution utility.
> >
> > (2) How the electrical distribution utility's disposition of such auction proceeds complies with the requirements of this section and the requirements of California Health & Safety Code sections 38500 et seq. (MID1)

> **Response:** We do not believe the proposed addition to the regulation is appropriate. The term "informational purposes" is overly vague. After reviewing

reports from electrical distribution utilities, ARB may wish to modify the regulation to change the allowance allocation approach.

Carbon pricing is an important function of the cap-and-trade regulation in that it promotes energy efficiency, conservation, and the instillation of greenhouse gas efficient technologies such as combined heat and power. It is critical that the allowance value given to electrical distribution utilities not be used to prevent the development of an appropriate carbon price in electric rates.

Due to these concerns, ARB retains the right to revoke free allocation if the use of allowance value by any electrical distribution utility is inconsistent with the goals of AB 32. We will use the reports from the electrical distribution utilities to inform these decisions in future rulemakings.

R-36. (multiple comments)
Comment: Section 95892 of the proposed regulation addresses how the auction revenue from directly allocated allowances may be used by IOUs. WPTF urges ARB to provide specific regulations that specifically preclude IOUs from being able to use the auction revenues for direct capital investment in energy technologies and infrastructure, including renewable resources, or in service offerings such as energy efficiency or demand response, that are also provided by competitive merchant generators and other competitive market participants. Allowing the use of auction revenue for these purposes would erode competitive markets by subsidizing utility-owned generation, transmission, and energy management programs at the expense of independent generators, transmission developers, and competitive providers of energy management services. WPTF recommends that a provision be added to the regulation to prohibit the use by IOUs of auction revenue for direct capital investments in emission reduction technologies, and instead should be used only for direct consumer rate relief that is available to all rate-payers. (WPTF)

Comment: The proposed regulation prescribes that the proceeds obtained from the monetization of allowances directly to POUs and IOUs shall be subject to limitations imposed by their Governing Bodies or the CPUC, as appropriate, and the "additional limitations set forth in section 95892(d)(3)." Section 95892(d)(3) further prescribes that auction proceeds obtained by an electrical distribution company shall "be used exclusively for the benefit of retail ratepayers consistent with the goals of AB 32, and may not be used for the benefit of entities or persons other than such ratepayers." While recognizing CARB's interest in ensuring that the allowance allocation policy and use of revenues is not used in a discriminatory manner or to competitive advantage, IEP remains concerned that the language in section 95892(d) fails to ensure that these objectives are achieved. The allowance could be used, either directly or indirectly, on behalf of "ratepayers" to achieve the purposes of AB 32 while still providing value to the utilities in the competition to develop and operate generation assets to serve California consumers. For example, if a utility proposed to build a utility-owned CHP, renewable, or pumped storage facility, undoubtedly it would be justified as needed to achieve the purposes of AB 32 and, by definition, it would be to benefit ratepayers or it would not be approved by the appropriate Governing Board (or CPUC). IEP remains concerned that the standard of review by CARB regarding the use of allowance revenue is not sufficient to protect against anti-competitive impacts particularly given the discretion of the various Governing Boards to interpret the standards. Accordingly, IEP recommends additional language to enhance the protections against anti-competitive, discriminatory outcomes in the use of auction revenues. Modify section 95892(d)(3) as follows:

> (3) Auction proceeds obtained by an electrical distribution utility shall be used exclusively for the benefit of retail ratepayers of each electrical distribution utility, consistent with the goals of AB 32, shall avoid discriminatory impacts as between utility-owned and non-utility-owned electrical generation, and shall foster a competitive environment for the development and operation of electric generation. Auction proceeds may not be used for the benefit of entities or persons other than such ratepayers.
> (A) Investor owned utilities shall ensure equal treatment of their own customers and customers of electricity service providers, community choice aggregators, and non-utility owned electric generators. (IEPA)

> **Response:** We believe the proposed addition to the regulation is not necessary. The CPUC must approve all new contracts and will determine how auction funds are spent according to the regulation. The CPUC ensures that all contracts are competitive and fair.

R-37. Comment: Energy utilities will be given allowances with the obligation to auction them. The proceeds from utility auctions will be subject to California Public Utilities Commission direction for the investor owned utilities and local governing boards for public utilities. Less desirable from a local government perspective, there is room under section 95892(d)(3) for the Regulation to be augmented with a paragraph that says "electrical distribution utilities shall (ensure that proceeds from allowance auctions are provided to local governments for programs that reduce greenhouse gas emissions)." Local governments are a key partner in realizing climate change goals, as CARB has recognized throughout its proceedings to implement AB 32. Local governments will be best able to assist CARB if we are provided incentive and opportunity to participate in the program. (LGSEC)

> **Response:** We believe that the existing regulatory language provides flexibility to accommodate this request. Local governments can work with the CPUC and local governing utilities to determine if local government projects meet the requirements of the regulation and, if so, the utilities could fund those projects if they meet the goals of AB 32.

Consumer Rebate Check

R-38. Comment: We support the proposed language on using allowance value to provide rebates to customers as long as the rebate is not on a per kWh basis (so as not to provide perverse incentive for increased usage). We encourage CARB to go one step further and specifically require the utilities to consider providing rebates, subject to the same restrictions currently in the regulations, to low-income customers. (KUSTIN10, EBERHARD)

> **Response:** Utility providers have the option to provide rebates to ratepayers. Rebates to ratepayers could be structured to provide the greatest amount of relief to low-income customers. As stated in Resolution 10-42, the Board agreed with the recommendations of the Economic and Allocation Advisory Committee, including financing economic opportunities and environmental improvements in disadvantaged communities.

R-39. (multiple comments)
Comment: We hope that you provide a stronger recommendation to the PUC on how to provide lump sum per capita dividend checks as the primary way to return revenue back to consumers rather than just through billing. (CPC5)

Comment: I want to emphasize the point about specifically defining ratepayer benefit. Currently the benefit is not defined at all. This should be a rebate check sent to ratepayers separately from their utility bill so that they receive the price signal first and financial adjustment secondarily. (CPC2)

Comment: I am particularly concerned about the electrical power sector. Ratepayers must be protected by returning allowance value directly to residential customers as a rebate check. This follows your expert economic panel's recommendation that "The largest share (roughly 75 percent) of allowance value should be returned to California households in the form of a dividend check. This also incentivizes conservation on the broadest level. (FRIEDENBERG)

Comment: We encourage use of allowance value to incentivize efficient combined heat and power (CHP). The AB 32 Scoping Plan calls for the state to increase CHP energy generation by 30,000 GWh, yet the cap and trade regulation provides no incentives for development or expansion of CHP. In fact, the threat of creating a cap and trade compliance obligation is likely to discourage facilities including wastewater treatment plants from installing or expanding efficient CHP systems. We therefore encourage ARB to direct some portion of allowance value to development of a program that incentivizes CHP. (CAWWCCG1, EMWD, BACWAAC))

> **Response:** The CPUC will determine the most cost-effective way to return auction revenue back to IOU ratepayers. The governing boards will make these decisions for the POUs. We do not support refunds based solely on the use of electricity. We agree that this type of "volumetric" rebate would distort the carbon price signal and fail to properly promote conservation of electricity, efficient combined heat and power, and distributed generation.

R-40. Comment: We are disappointed with the proposal to launch the Cap and Trade program by offering extensive allowances for free to the electricity sector. Auction revenue is necessary to create a stream of revenue to support vulnerable communities and to allow low income Californians to fully participate in the clean energy opportunities being created. Specifically, funding is needed to help low income households avoid increased energy costs, by improving home weatherization, energy efficiency programs, and bill pay assistance as needed. In addition, revenue is needed to direct clean energy opportunities, including job training, to communities disproportionately burdened by power plant pollution. (CIPAL)

> **Response:** Allowances are allocated to utilities on behalf of ratepayers, and the allowance value must be used on behalf of ratepayers. As stated in Resolution 10-42, the Board directed the Executive Officer to deposit a minimum of 10 percent of annual proceeds generated from the direct auction of allowances in the Air Pollution Control fund for appropriation by the Legislature to programs and projects that reduce GHG emissions or mitigate direct health impacts of climate change. We agree with the potential uses of allowance value recommended by the Economic and Allocation Advisory Committee, including financing economic opportunities and environmental improvements in disadvantaged communities. In Chapter II and Appendix J of the Staff Report, we recommend several uses for Air Pollution Control Fund proceeds, including the creation of a Community Benefit Fund. Such a fund could be used to promote projects that simultaneously reduce GHGs and co-pollutants, finance adaptation/preparedness for climate change health impacts, create improvements to mass transit and land use planning, facilitate natural resource conservation, and support non-utility energy-efficiency programs. Additionally, we also discussed a Low Carbon Investment Fund to promote projects that support a green technology workforce training program. We will initiate a public process to develop recommendations on the uses of allocation proceeds. We anticipate that the uses for allocation revenue in the Staff Report will be further developed.

Reporting Use of Allowances

R-41. (multiple comments)
Comment: We encourage CARB to require that each utility report to its regulator, CARB and in the case of POUs, the CEC, in a transparent, timely, and uniform fashion. POU reporting should be coordinated with current reporting on energy efficiency achievements and targets, as required by SB 1037 and AB 2021. Reports should indicate how the value from allowances under this program have brought additional energy efficiency and renewable energy investments. As part of the adaptive management plan, CARB, CEC, and PUC should hold a joint hearing every year to analyze these reports and consider the need for further regulatory oversight of allowance value distribution. The reporting requirements should be modeled after the federal ARRA reporting requirements, which allow regulators and individuals to track all expenditures on-line at www.Recovery.gov. Using the ARRA reporting software would

save money and avoid recreating the wheel. Setting a uniform reporting requirement for all utilities would allow CARB and the public to see how the allowance value is being spent and help build public trust in the program. Modify section 95892(e) as follows: Modify section 95892(e) as follows:

> (e) Reporting on the Use of Auction Proceeds. No later than June 30, 2013, and each calendar year thereafter, each electrical distribution utility shall submit a report to the Executive Officer, <u>and the appropriate designee at the CEC and PUC,</u> describing the disposition of any auction proceeds received in the prior calendar year. <u>In July of each year, ARB, CEC, and PUC shall hold a joint hearing to consider further action regulating the use of these proceeds based on the information included in these reports.</u> This report shall include:
>
> > (1) The monetary value of <u>allowance value</u> ~~auction proceeds~~ received by the electrical distribution utility <u>and how these resources compare to other resources used for clean energy investment as required by California law.</u>
> >
> > (2) How the electrical distribution utility's disposition of such auction proceeds complies with the requirements of this section and the requirements of California Health & Safety Code sections 38500 et seq.
> > (KUSTIN10, NRDC1, EBERHARD)

Comment: Require allowance value allocated to utilities to benefit ratepayers, meet the objectives of AB 32, and facilitate emission reductions above and beyond business as usual (BAU). (UCS2, CADMANS)

Comment: We support the requirement that all utility sector auction revenues be used for the benefit of ratepayers and to meet the goals of AB 32. If this benefit takes the form of rebates, the rebates should be limited to residential ratepayers and include all residential electricity customers within the utility's distribution service territory. If the benefit takes the form of clean energy investments, these investments should be made in accordance with the goals laid out in AB 32. (AB 32 identifies many goals, including "not disproportionately impact low-income communities," complement "air quality standards and reduce toxic air contaminant emissions," and consider "overall societal benefits, including reductions in other air pollutants, diversification of energy sources, and other benefits to the economy, environment, and public health." Health & Safety Code section 38562(b)). We are concerned that the language in the draft regulations requiring that auction revenues simply be spent for the benefit of ratepayers "consistent with the goals of AB 32," affords utilities insufficient direction and puts allowance value at risk of predominately subsidizing business as usual (aka investments that are already required under existing law). (UCS1, WALTERS, LUDLOW)

Comment: One element which we believe requires greater detail is the use of allowance value directed to electric distribution utilities. While we appreciate the language proposed for 15-day modification today, we need every assurance that every utility will invest the full value of allowances it receives for free on AB 32 related purposes, including energy efficiency, renewable energy, and rebates to low-income customers. CARB should also provide specific and uniform reporting requirements and guarantee oversight for all utilities receiving these free allowances. (CEERT)

Comment: Whether a utility sells into the consignment auction or not, it should be required to account for the full value of the allowances it received, and to report on these expenditures in a timely and transparent manner to its oversight body as well as to CARB. The full value of the allowances received, and thus the full amount to be invested in AB 32-related purposes, should be assessed by multiplying the number of allowances received by the auction price in the quarter the utility received them. Thus, if a publicly-owned utility received 15 million allowances but only put 10 million allowances up for sale at auction, the utility should be required to account for the full value of allowances received (15 million) not simply the portion put up for auction (10 million). In formula form, this means:

$ Invested = # Allowances Received * $ Auction Price

Requiring utilities to account for the full value of their allowance allocation will ensure that we are investing in the maximum cost-effective emissions reductions in the electricity sector, and not continuing on a business-as-usual path. Utilities engaged in the joint CPUC/CEC proceeding starting in 2006 and the ongoing CARB proceeding have pointed out the difficulty of being required to “pay twice,” once to acquire allowances, and once to invest in emissions reductions. The rationale for initially giving utilities allowances for free is to ensure that they only have to gather the capital necessary to invest in making the reductions. Requiring utilities to spend the equivalent value of their freely received allowances on cost-effective emissions reductions ensures that they invest in additional, cost-effective reductions. Our rough calculations indicate that the minimum total allowance value in the electricity sector will be approximately $11 billion over the life of the program (2012-2020). This is calculated using an auction price of $10/MMT, escalating at 5 percent plus 2.5 percent CPI per year, multiplied by projected allowances allocated in the electricity sector results in total sectorial allowance value of $10.859 billion. (KUSTIN10, EBERHARD)

Comment: The Air Resources Board and/or the CPUC must establish strong oversight to ensure that funds generated as a result of the regulation are only spent on any appropriate consumer rate relief and GHG-reducing measures such as energy efficiency and the use of renewables. Given the free allowance allocation provisions, it is of particular concern that there is investment in mitigation versus windfalls for any participants. (CEEIC)

Comment: Require every utility to invest the full value of allowances it receives for free in AB 32-related purposes. CARB should require all utilities that receive allowances for free to invest the full value of those allowances on AB 32-related purposes. (KUSTIN10, EBERHARD)

Response: We modified section 95892 of the regulation to include conditions and reporting requirements that limit the use of auction revenue (utilities' monetized allowance value). CPUC currently regulates the use of ratepayer funds and utility shareholder funds for energy efficiency and renewable energy. Furthermore, although the rate structure is complex, we believe electricity consumers need to see a price signal that the cost of GHG emissions creates in the price of electricity. CPUC remains committed to ensure that allowance value is used for the purposes listed in these comments. As directed by the Board in Resolution 10-42, we will continue to work with the CPUC and POUs to help monitor and provide input on this topic.

R-42. (multiple comments)
Comment: We recommend ARB provide clearer guidance to utilities on use of allowance value in the electricity sector. The current regulations simply guide electric utilities to use their auction revenue for the benefit of ratepayers, consistent with the goals of AB 32. We urge CARB to be more explicit and require that utilities first use auction revenue for energy efficiency programs that are cost-effective under AB 32's framework. Modify section 95892(d)(3) as follows:

(3) Auction proceeds obtained by an electrical distribution utility shall be used exclusively for the benefit of retail ratepayers of each electrical distribution utility, consistent with the goals of AB 32, and may not be used for the benefit of entities or persons other than such ratepayers.

<u>A. All electrical distribution utilities shall use allowance value first to invest in energy efficiency programs that are not already required by California law and that achieve cost-effective GHG emissions reductions, according to the requirements of AB 32. The PUC, CEC, and POU Boards shall work together to determine the minimum amount of allowance value that should be spent on energy efficiency and develop a methodology to determine which energy efficiency programs are additional to existing programs and cost-effective under AB 32. If an electrical distribution utility does not use this minimum amount towards such programs, it risks forfeiting receipt of future allowance value.</u>

<u>B. To the extent that an electrical distribution provider uses allowance value to invest in new renewable energy, it shall prioritize projects that achieve environmental and health co-benefits for Californians.</u>

C. Investor owned utilities shall ensure equal treatment of their own customers and customers of electricity service providers and community choice aggregators.

<u>D. All electrical distribution utilities shall consider the impacts of this program on low-income customers and devote allowance value, in accordance with section 95892(d)(3)(E) below, to offset the impacts of this program, if any, on low-income customers.</u>

E. To the extent that an electrical distribution utility uses allowance value ~~auction revenue~~ to provide ratepayer rebates, it shall provide such rebates with regard to the fixed portion of ratepayers' bills or as a separate fixed credit or rebate.

F. To the extent that an electrical distribution utility uses allowance value ~~auction revenue~~ to provide ratepayer rebates, these rebates shall not be based solely on the quantity of electricity delivered to ratepayers from any period after January 1, 2012. (EBERHARD, KUSTIN10, NRDC1)

Comment: CARB should provide greater clarity and direction on the distribution utilities' use of allowance proceeds and direct the use of allowance proceeds to minimize rate impacts to the distribution utilities' customers (section 95892(d)). The proposed regulation does not specify how allowance proceeds should be used by the distribution utilities. Praxair is concerned that without additional direction from CARB, allowance revenues could be used for the utility programs that may not benefit all distribution services customers, particularly those in electricity intensive industries interconnected at transmission voltages or receiving electric commodity in the competitive market. Praxair urges CARB to clarify section 95892 to ensure that allowance revenues are used to mitigate electricity cost impacts, especially in industries that are largely exposed to higher energy costs, such as the energy-intensive industrial gases industry. The proposed regulation (section 95892(d)(3)(A)) provides that "Investor Owned Utilities shall ensure equal treatment of their own customers and customers of electricity service providers and community choice aggregators." This is an important provision, and a similar directive should also apply to the publicly owned utilities' (POU) application of allowance value. The proposed regulation provides little guidance on how CARB would ensure that IOUs will distribute allowance proceeds in a manner that ensures parity between various types of customers. The reporting requirements on the use of allowance proceeds are very simplistic and will not result in meaningful information or guidance concerning a utility's use of allowance proceeds. The reporting requirements would only require that the reporting utility provide the monetary value of the auction proceeds and how the utility's use of the proceeds complies with AB 32 (section 95892(e)). The proposed regulation should also explicitly provide that CARB will coordinate with the CPUC through an open, public workshop process to discuss how the IOUs may use allowance revenue and how the CARB and the CPUC will ensure that the distribution of allowance revenue to customers does not have a discriminatory result. Praxair also suggests that CARB provide similar guidance to the POUs with respect to the application of allowances to benefit their customers. Praxair is concerned that similar facilities located within different service areas, one IOU and one POU, could potentially face different economic impacts in their electricity costs due to different applications of value from the CARB-allocated allowances. While true parity in the compliance burden between the different types of utilities is unlikely, potential differences to customer costs should not be exacerbated from vastly different applications of the allocated allowances. The reporting requirements should be expanded to provide enough information for CARB to fully determine that customers received equal treatment. CARB should include a new subsection (h) under section

95111 of the Amendments to the Mandatory Reporting Regulation. Modify section 95911(h) as follows:

(h) Additional Requirements for Electrical Distribution Utilities Eligible for Receipt of Direct Allocation of California Greenhouse Gas Emission Allowances. Electrical Distribution Utilities, as defined in Title 17 California Code of Regulations, Subchapter 10, Article 5, shall report the amount of allowance revenue received from each quarterly auction, as well as the Electrical Distribution Utility's use or distribution of the revenues as follows:

(1) The aggregate amount of allowance revenue received from each quarterly auction;
(2) The amount of revenue received from selling allowances in a secondary allowance market (i.e., allowance revenue received from sources other than the quarterly auctions);
(3) The amount of allowance revenue the distribution utility distributed in the form of bill relief to retail customers, including the number of customers that received allowance revenue in the form of rebates or other relief, the classification of customers that received rebates or other relief, and the amount of rebates or other relief by each classification of customer received;
(4) A list of programs that the distribution utility funded with allowance revenue, including the amount of allowance revenue applied to each program; and,
(5) The amount of allowance revenue that the utility did not spend or distribute during a reporting year. (PRAXAIR)

Comment: The use of auction revenue is important not only for political and legal reasons, but NextEra believes it is also an important part of ARB reaching their long term GHG reduction goals. Section 95892 of the proposed regulation suggests IOUs use auction revenues to the benefit of ratepayers in a manner consistent with the goals of AB 32. NextEra Energy feels ARB should be more proscriptive. There is an opportunity to use these auction revenues to invest in programs that will provide the framework for a low carbon future. Examples of these potential investments include but are not limited to; building transmission to renewable energy zones; developing new or improved electric generation technologies; alternative fuel distribution facilities; appliance efficiency upgrade/replacement programs; supplementing costs of renewable energy to electricity customers (NEXTERAENERGY)

Comment: ARB should give the CPUC and CEC more direct guidance on the potential uses for auction revenue. Any unfair competitive advantages for entities administering the revenues to customers must be avoided. (NEXTERAENERGY)

Comment: DRA supports the requirement that electric distribution utilities must auction the allowances directly allocated to them, and use the proceeds from the auctions to the benefit of ratepayers. DRA recognizes that the CPUC and local governing boards (for publicly-owned utilities) will have oversight over the proceeds from the sale of allowances, and if there is no clear guidance provided by ARB, there will likely be a proceeding at the CPUC to determine the final amount of investor-owned utility (IOU) proceeds dedicated to rebate programs or to other GHG-reduction programs that will “benefit ratepayers.” DRA is concerned that the Proposed Regulation is too vague to ensure that the allowance proceeds are used to directly benefit ratepayers. Without more specific language, DRA believes that there is a risk of the allowance proceeds being spent on programs or investments that may not translate to the direct cost savings that are necessary to balance the impacts of AB 32 programs on electricity rates. DRA recommends 100 percent of allowance value freely allocated to electric distribution utilities should be directly returned to ratepayers in the form of rebates. Rebates (as opposed to rate reductions) will ensure that the carbon price will still be reflected in retail rates and incentivize increased conservation and energy-efficiency activities. If the Proposed Regulation does not adopt this recommendation, DRA requests that ARB provide clear guidance in the Proposed Regulation as to where the allowance proceeds should be directed.(DRA)

> **Response:** We do not believe that the proposed changes are necessary. We believe that the guiding principal of benefitting the ratepayer according to AB 32 goals is appropriate. The CPUC and local governments will continue to have oversight on how auction proceeds allocated to electrical distribution utilities should be used. We will continue to work with these organizations to ensure that the funds are being used appropriately. This approach provides flexibility to the utilities to meet the needs of their respective ratepayers. Finally, the regulation requires utilities to submit annual reports to show how auction revenue is being used and to make sure that it follows the guidelines specified in the regulation.

R-43. Comment: Using auction proceeds to provide customer rebates—even on the fixed portion of ratepayers' bills—will discourage customers from adopting energy saving behaviors. A 2009 report published by The Center on Budget and Policy Priorities" articulates that "Providing relief in the form of reductions in the fixed portion of utility bill charges preserves the price signal of higher rates in the variable portion of the bill to the maximum extent possible, but that effect is largely blunted if consumers look only at the bottom line of their bill, where they would not experience the 'sticker shock' that could prompt changes in behavior." We recognize the desire to protect ratepayers from increases in electric bills, but recommend an alternative solution to providing rebates. This recommendation is based on the fact that energy audits lead directly to reduced GHG emissions which is in line with the goals of AB 32; identify energy-saving solutions in line with California's preferred loading order; identify energy-saving solutions while also contributing to decreases in electric bills, unlike rebates on energy bills; typically identify previously unidentified low or no-cost energy-saving solutions; and the establishment of an energy consumption threshold customers must exceed to participate will allow electrical distribution utilities to target energy consumers typically excluded from the numerous single-family residential energy efficiency programs. Modify section 95892(d)(3)(B) as follows:

(B)To the extent that an electrical distribution utility uses auction proceeds to mitigate increases in ratepayers' bills, it shall provide customers exceeding a specified threshold of energy consumption low or no cost energy audits in addition to a list of qualified contractors to select from. (MCKINSTRY)

> **Response:** We believe it is important that ratepayers are not unduly affected by this regulation. We modified the regulation to ensure that the CPUC and the POU governing boards have adequate flexibility in designing a mechanism to return allowance value to ratepayers. We believe that a carbon price signal in electric rates is necessary to create proper incentives for conservation and investment in efficient combined heat and power and distributed generation.

R-44. Comment: IOUs will have extra allowances to auction in a secondary market. Consumers Union feels strongly that, particularly in the case of IOUs, it would be more efficient to auction these allowances in the first place and return most of the revenue directly to consumers. (CONSUMERSUNION)

> **Response:** We do not agree. IOUs are required to auction their allowances according to section 95892.

R-45. Comment: Catholic Charities is concerned that ARB's proposal will provide electric utilities almost 100 percent free allocations. These free giveaways amount to windfall profits for polluting industries and will discourage greater energy efficiency. (CATHCHAR1)

> **Response:** We do not agree. The utilities must provide annual reports to ARB to show that they meet the requirements in the regulation and are using auction proceeds for purposes outlined in AB 32.

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IV. SUMMARY OF COMMENTS MADE DURING THE FIRST 15-DAY COMMENT PERIOD AND RESPONSES

A. LIST OF COMMENTERS

The table below identifies the comments received during the first 15-day comment period. Despite falling outside the scope of the first 15-Day Change Notice, a number of comments nevertheless are summarized and responded to below. Although ARB legally is not required to summarize and respond to these comments under the APA, we provided a response to these comments because it was felt the general public and interested stakeholders could benefit from the additional clarity provided by the responses.

Table IV-1: Comments Received During the 15-Day Comment Period

Abbreviation	**Commenter**
3DEGREES2	Ian McGowan, 3Degrees Written Testimony: 8/11/2011
AB32IG2	Shelly Sullivan, AB 32 Implementation Group Written Testimony: 8/11/2011
ABC2	Patrick Serfass, American Biogas Council for 2G-Cenergy Power Systems Technologies Inc.; AAT America Inc.; AEA Natural Systems; AgPower Group, LLC; Aikan North America, Inc.; Alten LLC; Great Plains Institute; American Crystal Sugar Company; Anchor-International, LLC; Andgar Corporation; Andrew Moss; BBI International; Ben Grodsky; BioCycle; BioEnergy; Technologies, Inc.; BIOFerm Energy Systems; Bio-Methatech Canada; Biothane LLC; BTS Italia Srl/GmbH; California Bioenergy LLC; Caterpillar; Christiaens Group; City of Des Moines Wastewater; Clean Energy Fuels Corporation; Clear Horizons LLC; Coker Composting & Consulting; Columbia Business School; Cornerstone Environmental Group; Dane County Department of Public Works, Highway and Transportation; David Border Composting Consultancy; Deaton & Associates, LLC; District of Columbia Water and Sewer Authority (DCWASA); DODA USA, Inc.; Douglas Ross; Effluential Synergies LLC; Eisenmann Corporation; Electrigaz Technologies Inc.; Element Markets, LLC; Enbasys GmbH; Endeavor Electric Inc.; Energy Solutions-OTB, LLC; Energy Systems Group; Entec Biogas USA; Environmental Credit Corp.; Environmental Fabrics; EnviTec Biogas AG; Essential Consulting Oregon, LLC; Evergreen Recycling Inc.; Everstech Consulting; Fair Oaks Dairy; FBi Buildings, Inc.; Ferdowsi University of Mashhad;

	FGH Keogh & Associates, PLLC; Flotech Services NA, Ltd.; Freeman White; Gaia Strategies; GaiaRecycle, LLC; GE Energy (General Electric); Geomembrane Technologies Inc.; GHD, Inc.; Green Power Conferences; Grober Group of Companies; Guascor North America; Harvest Power, Inc.; Homeland Renewable Energy, Inc.; Humboldt Waste Mgmt Authority; JSH International; Landia, Inc.; LANDTEC North America, Inc.; McGuireWoods LLP; Mercuria Energy America, Inc.; ML Strategies; MT-Energie USA Inc.; Municipal Biogas; MWM of America, Inc.; National Association of Clean Water Agencies; National Milk Producers Federation; NEO Energy, LLC; Northeast Energy Systems/Western Energy Systems; O'Brien & Gere; OmniGreen Renewables; Organic Matters, Inc.; Organic Waste Systems, Inc.; Pecos Valley Biomass Corp.; Peyton Wise; Quest Recycling Services; Reading Electric Renewables; REEthink, Inc.; Rollcast Energy, Inc.; Ron Skinner; Ronald Puthoff; Ros Roca; Sandvik Process Systems; SCC Americas; Scenic View Dairy, LLC; Science Policy Works International; Sheland Farms; Siemens Industry, Inc.; Sievers Family Farms, LLC; Silvernail Consulting, LLC; Sprucegrove Investment Management Ltd.; Stoel Rives LLP; Strategic Conservation Solutions; SUMA America, Inc.; SUNY College of Environmental Science and Forestry; Swedish Biogas International; Terra Viva, Inc.; The Climate Trust; The New Energy Company; The Stover Group; Todd Thorner Biogas; Turning Earth LLC; TW2E Holding B.V.; University of Wisconsin, Platteville; US Composting Council; UTS Residual Processing LLC; Vaughan Company, Inc.; Verliant Energy Partners; Yield Energy, Inc.; Zero Waste Energy LLC. Written Testimony; 8/10/2011
ACC4	Emily Rooney, Agricultural Council of California Written Testimony: 8/11/2011
ACERIO	Andrew Brown, ACE Cogeneration and Rio Bravo Written Testimony: 8/11/2011
ACMP	Jon M. Constantino, Association of Carbon Market Participants Written Testimony: 8/11/2011
AFPA2	Paul Noe, American Forest & Paper Association Written Testimony: 8/11/2011
AFPA3	Paul Noe, American Forest & Paper Association Written Testimony: 8/11/2011
AP	Armando Sanchez, Algonquin Power Written Testimony: 7/26/2011

APC2	Keith Adams, P.E., Air Products and Chemicals Written Testimony: 8/11/2011
BAAQMD3	Jack P. Broadbent, Bay Area Air Quality Management District Written Testimony: 8/9/2011
BANKS	Carla Banks Written Testimony: 8/11/2011
BARCLAYS	Kedin Kilgore, Barclays Capital Written Testimony: 8/11/2011
BERNSTEIN	Brock Bernstein Written Testimony: 8/11/2011
BLUESOURCE2	Jeff Cole, Blue Source Written Testimony: 8/11/2011
BONNEVILLEPWR2	Courtney Olive, Bonneville Power Administration Written Testimony: 8/1/2011
BP2	Ralph Moran, BP America Inc. Written Testimony: 8/11/2011
BPA	Kay Martin, Bioenergy Producers Association Written Testimony: 7/31/2011
BPA2	James Stewart, BioEnergy Producers Association Written Testimony: 8/11/2011
BROWNA	Alessandra Brown Written Testimony: 8/3/2011
CAC	Evelyn Kahl, Cogeneration Association of California Written Testimony: 8/11/2011
CACAN3	Claudia Reid, California Certified Organic Farmers; Jeanne Merrill, California Climate and Agriculture Network; Rebecca Spector, Center for Food Safety; David Runsten, Community Alliance with Family Farmers; Ken Dickerson, Ecological Farming Association; Dave Henson, Occidental Arts & Ecology Center Written Testimony: 8/11/2011
CACC2	Beth Vaughan, California Cogeneration Council Written Testimony: 8/11/2011
CACDGC2	Eric Wong, California Clean DG Coalition Written Testimony: 8/11/2011
CALCHAMBER3	Brenda Coleman, California Chamber of Commerce Written Testimony: 8/11/2011
CALFP3	John Larrea, California League of Food Processors Written Testimony: 8/11/2011
CALPINE3	Kassandra Gough, Calpine Corporation Written Testimony: 8/11/2011

CANTORCO2E2	Josh Margolis, CantorCO2e Written Testimony: 8/10/2011
CAPCOA3	Thomas Christofk, California Air Pollution Control Officers Association Written Testimony: 8/11/2011
CAR4	Gary Gero, Climate Action Reserve Written Testimony: 8/10/2011
CARBONSHARE2	Mike Sandler, Carbon Share Written Testimony: 8/4/2011
CARR	Brian Carr Written Testimony: 8/10/2011
CASTLEG	Emily Rooney, Agricultural Council of California for Cathleen Galgiani, California State Assembly; Connie Conway, California State Assembly; David Valadao, California State Assembly; Doug LaMalfa, California State Senate; Henry Perea, California State Assembly; Fiona Ma, California State Assembly; Bill Berryhill, California State Assembly; Linda Halderman, California State Assembly; Shannon Grove, California State Assembly; Alyson Huber, California State Assembly; Kristen Olsen, California State Assembly; Tom Berryhill, California State Senate; Jean Fuller, California State Senate; Dan Logue, California State Assembly; Sam Blakeslee, California State Senate; Jim Nielsen, California State Assembly Written Testimony: 8/10/2011
CAW	Andy Katz, Breathe California; Nick Lapis, Californians Against Waste; Brian Nowicki, Center for Biological Diversity; Timothy O'Connor, Environmental Defense Fund; Monica Wilson, Global Alliance for Incinerator Alternatives; Jim Metropulos, Sierra Club California; Peter Miller, Natural Resources Defense Council Written Testimony: 8/11/2011
CBD4	Nick Lapis, Californians Against Waste; Paul Mason, Pacific Forest Trust; Peter Miller, Natural Resources Defense Council; Brian Nowicki, Center for Biological Diversity; Timothy O'Connor, Environmental Defense Fund; Michelle Passero, The Nature Conservancy Written Testimony: 8/11/2011 **In addition, 7 supplemental documents were submitted**
CBE2	Greg Karras, Communities for a Better Environment Written Testimony: 8/11/2011 **In addition, 6 supplemental documents were submitted**
CBEA3	Julee Malinowski-Ball, California Biomass Energy Alliance Written Testimony: 8/11/2011

CCC2	Robert Wyman, California Climate Coalition Written Testimony: 8/11/2011
CCEEB3	Robert W. Lucas and Gerald D. Secundy, California Council for Environmental and Economic Balance Written Testimony: 8/11/2011
CCGG2	Casey Creamer for California Cotton Ginners and Growers Associations; Nisei Farmers League; Western Agricultural Processors Association Written Testimony: 8/11/2011
CCL1	Mark Reynolds, Citizens Climate Lobby Written Testimony: 7/26/2011
CCL2	Mark Reynolds, Citizens Climate Lobby Written Testimony: 7/29/2011
CCL3	Amy Bennett, Citizens Climate Lobby Written Testimony: 7/29/2011 **In addition, 1 supplemental document was submitted**
CCL4	Jerry Hinkle, Citizens Climate Lobby, Sierra Club, and Environmental Defense Fund Written Testimony: 7/30/2011
CE2CC	Gregory Arnold, CE2 Carbon Capital Written Testimony: 8/11/2011
CERP4	Kyle Danish, Coalition for Emission Reduction Policy Written Testimony: 8/11/2011
CFA2	Steven Brink, The California Forestry Association Written Testimony: 8/11/2011
CFBF	Cynthia Cory, California Farm Bureau Federation Written Testimony: 8/11/2011
CHEVRON3	Stephen Burns, Chevron; Jean-Philippe Brisson, Linklaters, P.C. for Chevron Written Testimony: 8/11/2011
CIG2	Charles Purshouse, Camco International Group, Inc. Written Testimony: 8/11/2011
CIPA	Norman Plotkin, California Independent Petroleum Association Written Testimony: 8/11/2011
CLABS	Alexander E. Helou, P.E., City of Los Angeles Bureau of Sanitation Written Testimony: 8/10/2011
CLADPW	Pat Proano, County of Los Angeles Department of Public Works Written Testimony: 8/11/2011
CLECA	William H. Booth, California Large Energy Consumers Association Written Testimony: 8/11/2011

CMTA3	Dorothy Rothrock, California Manufacturers and Technology Association Written Testimony: 8/11/2011
CNE	Mary Lynch, Constellation NewEnergy Inc. Written Testimony: 8/11/2011
CONOCO2	Chris Chandler, ConocoPhillips Company Written Testimony: 8/11/2011
COPC3	Roger Williams, Carbon Offset Providers Coalition Written Testimony: 8/11/2011
COVANTA	Ellie Booth, Covanta Energy Written Testimony: 8/11/2011
CPC6	Barry Vesser, Climate Protection Campaign Written Testimony: 8/11/2011
CRPE4	Sofia Parino, Center on Race, Poverty & the Environment; Maria Covarrubias, Comité ROSAS; Domitila Lemus, Comité Unido de Plainview; Maria Buenrostro, Comité Luchando por Frutas y Aire Limpio; Penny Newman, the Center for Community Action and Environmental Justice; Linda Mackay, TriCounty Watchdogs; Jesse Marquez, Coalition for a Safe Environment; Angela Meszros; Strela Cervas, California Environmental Justice Alliance; Tom Frantz, Association of Irritated Residents; Salvador Partida, Committee for a Better Arvin; Ruth Martinez, Comité Si Se Puede; Ana Ceballor, La Voz de Toniville; Teresa DeAnda, El Comité Para El Bienestar de Earlimart; Gary Lasky, Sierra Club Tehipite Chapter; Shabaka Heru, Society for Positive Action; Caroline Farrell Written Testimony: 8/11/2011 **In addition, 4 supplemental documents were submitted**
CRS2	Jennifer Martin, Center for Resource Solutions Written Testimony: 8/7/2011
CSCME4	John Bloom, Coalition for Sustainable Cement Manufacturing and Environment Written Testimony: 8/11/2011
CSI	Brett Guge, California Steel Industries, Inc. Written Testimony: 8/11/2011
CTA2	Eric Sauer, California Trucking Association Written Testimony: 8/11/2011
DAVISSTEIN2	Jessica Davis-Stein Written Testimony: 8/9/2011
DWR2	Veronica Hicks, Department of Water Resources Written Testimony: 8/11/2011

EDF4	Tim O'Connor, Environmental Defense Fund Written Testimony: 8/11/2011
EDF5	Erica Morehouse & Tim O'Connor, Environmental Defense Fund; Alex Jackson & Kristin Eberhard, Natural Resources Defense Council; Paul Mason, Pacific Forest Trust; Jim Metropulos, Sierra Club California Written Testimony: 8/11/2011
EDLA	Jim Stewart, Earth Day Los Angeles Written Testimony: 8/11/2011
EIGHTUTILITIES	Vince Brar, City of Cerritos; Jonathan Daly, City of Corona; Jeannette Olko, Moreno Valley Municipal Utility; David Brownlee, City of Needles; Fred Lyn, City of Rancho Cucamonga; Jenele Davidson, City of Victorville; Stuart Robertson, Eastside Power Authority; W. Kent Palmerton, Power & Water Resources Pooling Authority Written Testimony: 8/11/2011
EM	Randall Lack, Element Markets, LLC Written Testimony: 8/11/2011
EOSC3	Jeff Cohen, EOS Climate Written Testimony: 8/11/2011
EPUC2	Evelyn Kahl, Energy Producers and Users Coalition Written Testimony: 8/11/2011
EVMKTS2	Lenny Hochschild, Evolution Markets Inc. Written Testimony: 8/11/2011
EXXONMOBIL	Derek B. Wheeler, ExxonMobil Refining and Supply Written Testimony: 8/11/2011
FINITE	Sean Carney, Finite Carbon Corporation Written Testimony: 8/11/2011
FIRSTENVIRON3	Jay Wintergreen, First Environment Inc. Written Testimony: 8/11/2011
FISCHER	Sheila Fischer Written Testimony: 7/27/2011
FORMLETTER12	Richard Moore **72 additional commenters submitted similar comments** Written Testimony: 8/2/2011
FRIENDSOFEARTH2	Kate Horner, Friends of the Earth US; Rolf Skar, Greenpeace; Victor Menotti, International Forum on Globalization; Bill Barclay, Rainforest Action Network Written Testimony: 8/11/2011

FRIENDSOFEARTH3	Friends of the Earth US, Amazon Watch, Center for Biological Diversity, Global Justice Ecology Project, Global Witness, Greenpeace, International Forum on Globalization, International Indian Treaty Council, Justice in Nigeria Now, Rainforest Foundation US Written Testimony: 9/27/2011
GA	Michael Gardner, Gypsum Association Written Testimony: 8/5/2011
GANA2	Bill Yanek, Glass Association of North America Written Testimony: 8/11/2011
GEAG	Jeffrey Fort, GHG Early Action Group for AEP Energy Services, Inc.; Environmental Capital Management LLC; Excelsior Capital Management, LLC; Hudson Technologies, Inc.; NRG Energy, Inc.; Remtec International, Inc. Written Testimony: 8/11/2011
GIC	Nicholas W. van Aelstyn, Beveridge & Diamond, P.C. for Guardian Industries Corp. Written Testimony: 8/11/2011
GIESE	Mark M. Giese Written Testimony: 7/27/2011
GOALLINE	Joel Lepoutre, Goal Line LLP Written Testimony: 8/12/2011
GOEDJEN2	Robert Goedjen Written Testimony: 7/25/2011
GPI2	William Heatley, Graphic Packaging International Written Testimony: 8/10/2011
GPI3	Bill Buchan, Graphic Packaging International Written Testimony: 8/5/11
GPI4	Bill Buchan, Graphic Packaging International Written Testimony: 8/5/11
GPI5	Bill Buchan, Graphic Packaging International Written Testimony: 8/5/11
GREENX	Kari Larsen, Green Exchange Written Testimony: 8/11/2011
GRINNELL	Joseph Grinnell Written Testimony: 8/11/2011
HDPP4	Bradley K. Heisey, High Desert Power Project Written Testimony: 8/10/2011
IBERDROLA	Laura Beane, Iberdrola Renewables Written Testimony: 8/11/2011
ICCT3	Alan Lloyd, International Council on Clean Transport Written Testimony: 8/11/2011

IEPA2	Steven Kelly and Amber Riesenhuber, Independent Energy Producers Association Written Testimony: 8/11/2011
IETA3	Henry Derwent, International Emissions Trading Association Written Testimony: 8/11/2011
IGPACC	Rob Simon, The Industrial Gases Panel of the American Chemistry Council Written Testimony: 8/11/2011
INDENVASSOC2	Patty Krebs, Industrial Environmental Association Written Testimony: 8/11/2011
JM	Bruce D. Ray, Johns Manville Written Testimony: 8/11/2011
JOINTUTILITIES	Lily Mitchell for The California Municipal Utilities Association, Liberty Energy, Los Angeles Department of Water and Power, Modesto Irrigation District, Northern California Power Agency, Pacific Gas and Electric Company, PacifiCorp, Sacramento Municipal Utility District, San Diego Gas and Electric Company, Southern California Edison Company, Southern California Public Power Authority, and Turlock Irrigation District Written Testimony: 8/10/2011
KENNERLY2	Justin Kennerly Written Testimony: 7/27/2011
KENNEY	Daniel Kenney Written Testimony: 7/30/2011 **In addition, 1 supplemental document was submitted**
KUSTIN13	Bonnie Holmes-Gen, American Lung Association in California; Andy Katz, Breathe California; Betsy Reifsnider, Catholic Charities, Diocese of Stockton; Nidia Bautista, Coalition for Clean Air; Tyson Eckerle, Energy Independence Now; C.C. Song, Greenlining Institute; Diane Bailey, Natural Resources Defense Council; Jim Metropulos, Sierra Club California; Michelle Passero, The Nature Conservancy; Jasmin Ansar, Union of Concerned Scientists Written Testimony: 8/11/2011
KUSTIN15	Brian Nowicki, Center for Biological Diversity; Tyson Eckerle Energy Independence Now; Jim Metropulos, Sierra Club California Written Testimony: 8/11/2011

KUSTIN16	Andy Katz, Breathe California; C.C. Song, Greenlining Institute; Susan Stephenson, Interfaith Power and Light; Alex Jackson & Kristin Eberhard, Natural Resources Defense Council; Jim Metropulos, Sierra Club California; Laura Wisland, Union of Concerned Scientists Written Testimony: 8/11/2011
LADWP4	Lorraine Paskett, Los Angeles Department of Water and Power Written Testimony: 8/11/2011
LASD3	Stephen R. Maguin and Frank R. Caponi, Los Angeles County Sanitation Districts Written Testimony: 8/11/2011
LGCRE2	John Holladay, Local Government Coalition for Renewable Energy Written Testimony: 8/11/2011 **In addition, 11 supplemental documents were submitted**
LGSEC2	Jennifer K. Berg, Local Government Sustainable Energy Coalition Written Testimony: 8/10/2011
LSPOWER	Jennifer Chamberlin, LS Power Written Testimony: 8/11/2011
MARTINN2	Nicholas Martin, American Carbon Registry; Tiffany McCormick Potter, EcoAnalytics; Scott Nissenbaum, Finiti Carbon Corporation; Daniel S. Press, Van Ness Feldman Written Testimony: 8/10/2011
MARTINN3	Nicholas Martin, American Carbon Registry Written Testimony: 8/11/2011
MCLP	Brian Walker, Martinez Cogen Limited Partnership Written Testimony: 8/11/2011
MID3	Joy Warren, Modesto Irrigation District; Elizabeth Hadley, Redding Electric Utility; Dan Severson, Turlock Irrigation District Written Testimony: 8/11/2011
MILLERCOORS	Jim Mattesich, GreenbergTraurig, P.C. for MillerCoors Written Testimony: 8/12/2011
MORSE2	Susan Morse Written Testimony: 7/25/2011
MSCG3	Steve Huhman, Morgan Stanley Capital Group, Inc. Written Testimony: 8/11/2011
MSR	Martin Hooper, M-S-R Public Power Agency Written Testimony: 8/11/2011
MURRAYD	Douglas Murray Written Testimony: 7/26/2011

MWDSC3	Jeffrey Kightlinger, The Metropolitan Water District of Southern California Written Testimony: 8/11/2011
NAACP	Paul La Follette, National Association for the Advancement of Colored People and American Civil Liberties Union Written Testimony: 7/27/2011
NAES	Thomas Corr, Greg Bass and Justin Pannu, Noble Americas Energy Solutions Written Testimony: 8/11/2011
NAIMA2	Angus E. Crane, North American Insulation Manufacturers Association Written Testimony: 8/11/2011
NC8	Michelle Passero, The Nature Conservancy Oral Testimony: 8/11/2011
NCPA3	Susie Berlin, McCarthy & Berlin, P.C. for Northern California Power Agency Written Testimony: 8/11/2011
NEWFOREST2	Brian Shillinglaw, New Forests Written Testimony: 8/9/2011
NEXTERAENERGY2	Kyle Boudreaux, NextEra Energy Resources Written Testimony: 8/11/2011
NLA	Arline Seeger, National Lime Association Written Testimony: 8/5/2011
OFFSETSWG3	Bruce McLaughlin, Offsets Working Group for Joy Warren, Modesto Irrigation District; Elizabeth Hadley, City of Redding; Michael Bloom, City of Roseville; Timothy Tutt, Sacramento Municipal Utility District; Dan Severson, Turlock Irrigation District Written Testimony: 8/11/2011
OPC2	Carl Wirdak, Occidental Petroleum Corporation Written Testimony: 8/11/2011
OWENSIL2	Mark Tussing, Owens-Illinois Written Testimony: 8/11/2011
PACIFICOR3	James Campbell, PacifiCorp Written Testimony: 8/11/2011
PCAPCD2	Thomas Christofk, Placer County Air Pollution Control District Written Testimony: 8/11/2011
PEBI	Michael Mazowita, P.E. Berkeley, Inc.; Sean P. Lane, Olympus Power, LLC Written Testimony: 8/11/2011
PEC	Don Burkard, Panoche Energy Center Written Testimony: 8/11/2011

PFT3	Paula Swedeen, The Pacific Forest Trust Written Testimony: 8/11/2011
PGE4	John W. Busterud, Pacific Gas and Electric Company Written Testimony: 8/11/2011
PGPPC	William Sims, Procter & Gamble Paper Products Company Written Testimony: 8/11/2011
PNA	Pamela A. Rygalski, Pilkington North America, Inc. Written Testimony: 8/11/2011
POWEREX	Nicholas W. van Aelstyn, Beveridge & Diamond, P.C. for Powerex Corp Written Testimony: 8/11/2011
PPGI	Ray Yee, PPG Industries Written Testimony: 8/11/2011
PRAXAIR2	Gerald Miller, Praxair Inc. Written Testimony: 8/11/2011
REMA2	Josh Lieberman, Renewable Energy Markets Association Written Testimony: 8/11/2011
RNPBEF	Adam Schumaker, Renewable Northwest Project; Megan Walseth Decker, Renewable Northwest Project; Margie Gardner, Bonneville Environmental Project Written Testimony: 8/11/2011
SCAQMD4	Barry Wallerstein, South Coast Air Quality Management District Written Testimony: 8/11/2011
SCE3	Jennifer Tsao Shigekawa and Nancy Chung Allred, Southern California Edison Company Written Testimony: 8/11/2011
SCPPA6	Norman Pederson, Southern California Public Power Authority Written Testimony: 8/11/2011
SCPPA7	Norman Pederson, Southern California Public Power Authority Written Testimony: 8/11/2011
SCS2	Robert Hrubes, Scientific Certification Systems Written Testimony: 8/2/2011
SEMPRA3	Tamara Rasberry, Southern California Gas Company, San Diego Gas & Electric Company, Sempra Energy Utilities Written Testimony: 8/11/2011
SEMPRAGEN	Shawn Bailey, Sempra Generation Written Testimony: 8/11/2011
SES	William Gibbes, Sustainable Energy Solutions LLC Written Testimony: 7/28/2011

SFMAYOR3	Calla Ostrander, City and County of San Francisco Department of Environment Written Testimony: 8/11/2011
SHELLOIL	Sara M. O'Neill, Shell Oil Company Written Testimony: 8/11/2011
SIERRACLUBCA5	Jim Metropulos & Michael Endicott, Sierra Club California Written Testimony: 8/11/2011
SMUD3	William Westerfield III, Sacramento Municipal Utility District Written Testimony: 8/11/2011
SOLARTURBINES3	Craig Anderson, Solar Turbines Written Testimony: 8/10/2011
STEELEBR	Bruce Steele Written Testimony: 8/10/2011
STEUBE	Milan Steube Written Testimony: 8/11/2011
SVM2	Ross May, Searles Valley Minerals Written Testimony: 8/5/2011
SWC3	Terry Erlewine, State Water Contractors Written Testimony: 8/11/2011
TASKFORCE	Margaret Clark, Los Angeles County Solid Waste Management Committee/Integrated Waste Management Task Force Written Testimony: 8/9/2011
TCF2	Chris Kelly, The Conservation Fund Written Testimony: 8/2/2011
TCT	Lucy Brehm, The Climate Trust Written Testimony: 8/11/2011
TEA	Rudy Stefenel, Thorium Energy Alliance Written Testimony: 7/25/2011
TESORO2	Daniel Riley, Tesoro Companies, Inc. Written Testimony: 8/11/2011
TI	Carole J. Stapper, Temple-Inland Written Testimony: 8/10/2011
TPI5	Erin Craig, TerraPass Inc. Written Testimony: 8/11/2011
TVRP	Rick Brown, TerraVerde Renewable Partners Written Testimony: 7/31/2011
TWS	Ann Chan, The Wilderness Society Written Testimony: 8/10/2011
UBCSSB	James Tansey, University of British Columbia Sauder School of Business Written Testimony: 8/11/2011

UC3	Daniel M. Dooley, University of California Written Testimony: 8/11/2011
UCB2	William Stewart, University of California Berkeley Written Testimony: 8/2/2011
UCS6	Norris McDonald, African American Environmentalist Association; Bonnie Holmes-Gen, American Lung Association in California; Andy Katz, Breathe California; Susan Stephenson, California Interfaith Power and Light; Nick Lapis, Californians Against Waste; Betsy Reifsnider, Catholic Charities, Diocese of Stockton; Brian Nowicki, Center for Biological Diversity; James J. Provenzano, Clean Air Now; Ann Hancock, Climate Protection Campaign; Nidia Bautista, Coalition for Clean Air; Tyson Eckerle, Energy Independence Now; C.C. Song, Greenlining Institute; Katy Yan, International Rivers; Kevin Hamilton, Medical Advocates for Healthy Air; Ron Sundergill, National Parks Conservation Association; Jena Price, Planning and Conservation League; Anne Kelsey Lamb, Regional Asthma Management and Prevention; Michael Endicott, Sierra Club California; Dan Kalb, Union of Concerned Scientists Written Testimony: 8/11/2011
UCS7	Dan Kalb and Jasmin Ansar, Union of Concerned Scientists Written Testimony: 8/11/2011
UNITEDAIRLINES2	Jimmy Samartzis, United Airlines Written Testimony: 8/11/2011
UPI	Corre Javernick, USS-POSCO Industries Written Testimony: 8/11/2011
VALERO2	Matthew H. Hodges for Patrick Covert, Valero Companies Written Testimony: 8/11/2011
VCSA	David Antonioli, Verified Carbon Standard Association Written Testimony: 8/11/2011
VEA	Curt Ledford, Valley Electric Association Written Testimony: 8/11/2011
WAPA2	Koji Kawamura, Western Area Power Administration Written Testimony: 8/8/2011
WEC2	Doug Davie, Wellhead Electric Company Written Testimony: 8/11/2011
WILLIAMSZ2	Laurie Williams and Allan Zabel Written Testimony: 8/10/2011
WIRA3	Craig Moyer, Western Independent Refiners Association Written Testimony: 8/11/2011

WM3	Charles White, Waste Management Written Testimony: 8/11/2011 **In addition, 7 supplemental documents were submitted**
WPTF2	Clare Breidenich, Western Power Trading Forum Written Testimony: 8/11/2011
WSPA3	Catherine Reheis-Boyd, Western States Petroleum Association Written Testimony: 8/11/2011
YUROKTRIBE	John Corbett, Yurok Tribe, Office of the Tribal Attorney Written Testimony: 8/11/2011

B. AB 32 / CAP-AND-TRADE DESIGN

AB 32

General/Miscellaneous

B-1. Comment: California should go further to recommend that U.S. EPA integrate its new source review program for greenhouse gas-emitting sources into the NSPS program so that greenhouse gas-reducing facility modifications or new facility clean technology investments are not made more costly nor unduly delayed. A single, integrated program under AB 32 for California sources will be critical to assuring that California can meet its AB 32 goals expeditiously. (CCC2)

> **Response**: This comment falls outside the scope of the first 15-day changes to the regulation. Nevertheless, as stated in the responses to the 45-day comments, we recognize the importance of harmonization between State and federal GHG emissions-reduction requirements. This is reflected in Board Resolution 10-42, wherein the Board directed the Executive Officer to work with U.S. EPA on the development of a federal regulatory framework to grant delegation or equivalency to California's climate change program where appropriate.

Cap-and-Trade

General/Miscellaneous

B-2. Comment: The Regulations repeatedly indicate that an important function of offsets is to keep the costs of compliance low and thereby prevent leakage of California's industry and attendant polluting activities to other jurisdictions, as well as to address other sectors of the economy not subject to the cap. Leakage of emissions is a significant concern. However, the potential for leakage to occur is not an excuse for adopting a fatally flawed and unworkable approach, such as Cap and Trade with greenhouse gas offsets. In addition, relying solely on compliance caps and offsets to reduce emissions, rather than an increase in prices, hurts many of the incentives that would drive the rapid transition to a clean-energy economy needed to avert dangerous climate change. For instance, if CARB were to adopt carbon fees that rise predictably to insure that clean energy will become cost-competitive with fossil fuels within a known time frame, this would create huge incentives for a shift in private investment from fossil fuel energy into clean energy infrastructure and innovation as well as in energy efficiency. Similarly, individuals and businesses would experience a strong incentive to be creative in reducing their carbon footprint. In this respect, the cost containment approach of greenhouse gas offsets is not only lacking in integrity but also undermines critical incentives needed to provide the rapid reductions without which costly and potentially irremediable effects of climate change are likely to become inevitable. As noted in the Scoping Plan, one way to address leakage is "border adjustments," adding costs to goods that arrive from jurisdictions whose regulations do not have programs to address greenhouse gases and rebating costs to goods that travel from California to other jurisdictions (see Supplement at p.92). While such border adjustments can be more easily imposed on international trade, it may be possible to impose such adjustments on interstate commerce as long as the adjustments merely create a level playing field for out of state businesses and are not protectionist. Essentially, CARB fails to acknowledge that higher prices for activities that produce greenhouse gases are an extremely valuable tool for driving greenhouse gas reductions. CARB instead claims that keeping costs low is a higher value, discarding the alternative as politically and legally untenable, rather than analyzing this alternative as required by the Superior Court decision and State law. (WILLIAMSZ2)

Response: These comments fall outside the scope of the first 15-day change notice. Nevertheless, as discussed in the Staff Report, we analyzed a number of alternatives to the regulation, including the carbon tax mentioned by the commenter, and concluded that the cap-and-trade regulation was the best option. Compared to a carbon tax or fee, the cap-and-trade approach will result in a lower marginal cost of control. As stated in the responses to the 45-day comments, the cap-and-trade regulation will minimize the costs to industry and will minimize the costs passed through to consumers and lessen any impacts on individuals. We also included several cost-containment measures that are integrated into the program such as the use of offsets, three-year compliance periods, and the allowance price containment reserve.

If we find that leakage is occurring despite the safeguards in the regulation, we will examine mechanisms to address leakage, including border adjustments or changes to the allowance distribution systems, and will revise the operation and/or design of the program accordingly. Currently, we utilized a border adjustment for electricity in the form of the first deliverer compliance obligation because the requisite data are available, and because of the express direction in AB 32 to address electricity imports.

See also response to Comment K-25 in the 45-day responses.

B-3. Comment: We remain concerned that the market, as currently proposed, remains highly dependent on unpredictable future contingencies, including the degree of linkage to other jurisdictions (if any), the actual availability of verifiable offsets, the extent to which consumer demand will respond as predicted to carbon and energy prices and the degree of emissions performance of the AB 32 complementary measures. Staff has recognized that such contingencies ultimately will have a very material impact on California carbon prices. The Board should establish a periodic monitoring and reporting process by which such key elements can be carefully tracked and reported so that the Board can consider and, as appropriate, implement any necessary program adjustments. We strongly recommend that the Board require the staff, consulting with other appropriate state agencies, departments and commissions, to prepare an annual (or more frequent) report assessing the following items: (1) allowance, auction and offset supply and price (including offset project characterizations by sector, jurisdiction, verifying entities and other relevant information); (2) consumer demand response to energy prices and other signals; (3) greenhouse gas emissions performance of the AB 32 complementary measures (including at a minimum the low carbon fuel standard, the motor vehicle program, the renewable electricity standard and the sustainable communities program) relative to projected performance; (4) electricity prices; (5) transportation fuel prices; (6) employment levels and trends for all regulated sectors; (7) permitting activity for all regulated sectors; (8) leakage determinations; and (9) such other factors as the Board may designate regarding AB 32 program performance. Depending upon the findings of such annual (or other periodic) reports, the Board should be prepared to implement appropriate cost-containment mechanisms, circuit-breakers or other program protections. (CCC2)

> **Response**: This comment falls outside the scope of the first 15-day change notice. Nevertheless, as stated in the responses to the 45-day comments, we are committed to regular reviews of the implementation of the regulation, providing periodic updates to the Board, and proposing modifications to the regulation, as needed. This is also reflected in Board Resolution 10-42, wherein the Board directed the Executive Officer to update the Board annually on the status of the cap-and-trade program. We believe the language in the Resolution provides for reports to the Board on any issues of concern.

B-4. Comment: Section 95812(c)(4) references section 95151(a)(1) in the MRR. Section 95151(a)(1) no longer exists in the MRR. WSPA recommends that ARB correct this since section 95151(a)(1) no longer exists. (WSPA3)

> **Response**: We agree and modified section 95812(c)(4) as suggested by the commenter. The section now includes the applicability threshold within the section rather than referring to section 95151(a)(1).

B-5. Comment: The delay to the start date of the Cap and Trade program was an unfortunate development. Any changes to a developing market have real implications. Entities are making arrangements today in order to provide reliable electric service for future years. These entities must plan years in advance and are currently securing the resources to provide that service. A shift in policy that changes potential GHG liability associated with electricity affects the price and value of those services. NextEra would like to urge ARB to give entities as much lead time as possible when it plans to make major changes to the program. This will potentially lessen the adverse impacts on both the electricity and carbon markets. (NEXTERAENERGY2)

> **Response**: We understand the concerns of the commenter. However, we believe it was necessary to begin enforcement of the compliance obligation in 2013 of the cap-and-trade program to ensure that the central elements of the regulation (auctions, allocations, oversight, and enforcement) were developed and tested before moving into the first compliance year. We believe the adoption of this regulation will provide the market with certainty about the program's direction prior to enforcement of the compliance obligation. With regard to

providing adequate lead time prior to potential changes in the program, we agree with the commenter that we should provide as much lead time as possible.

B-6. Comment: PEB is an active member of the California Cogeneration Council (CCC) and fully supports the comments made by Beth Vaughn in a letter addressed to you on August 11, 2011. (PEBI)

Response: We acknowledge the comment. Please refer to the ARB responses directed to the relevant comments submitted by parties noted by the commenter.

B-7. Comment: NextEra supports the comments submitted by both the Independent Energy Providers (IEP) and The Western Power Trading Forum (WPTF). (NEXTERAENERGY2)

Response: We acknowledge the comment. Please refer to the ARB responses directed to the relevant comments submitted by parties noted by the commenter.

B-8. Comment: To the extent that CARB pursues a Cap and Trade program under AB 32, Valero herein adopts by reference the comments on the Cap and Trade Regulation submitted by the AB 32 Implementation Group and the California Manufacturers and Technology Association. (CMTA)(VALERO2)

Response: We acknowledge the comment. Please refer to the ARB responses directed to the relevant comments submitted by parties noted by the commenter. ARB may not respond to comments that do not address “15-day” modifications to the regulation.

B-9. Comment: We urge ARB to ensure that the infrastructure and programs necessary to support the objectives and requirements of a Cap and Trade program are fully developed before adopting a final rule. (VALERO2)

Response: We believe that the modifications to the regulation will ensure that the program is fully developed and tested before moving into the first compliance year.

B-10. (multiple comments)
Comment: The complexity of the proposed regulations for a Cap and Trade program illustrates the advantages of a fee and dividend system. Issues, such as offsets, and market manipulation problems are not present in a fee and dividend program where gradually increasing fees are set on fossil fuels. Other important advantages of fee and dividend are that since the proceeds collected are returned to the people, there is no depressing economic effect, it is politically acceptable to many who oppose cap and trade since it is revenue neutral and can be supported even by those groups that usually oppose all taxes. A system that is revenue neutral and results in a dividend check in each voter's mailbox would be attractive to many of those who typically oppose

all taxes. ARB needs to give a fair hearing to a fee and dividend program before it adopts an incredibly complex and problematic cap and trade program. (CARR)

Comment: ARB has heard from many advocacy groups voicing concerns about cap and trade and market mechanisms' potential impact on low-income and disadvantaged communities. Dividends can directly address their concerns about inequality and the regressive impact on poor people when energy and fuel prices rise. ARB can start us down the path to equal ownership of this atmospheric commons. Everyone gets the same dividend or share. People get paid as they gain understanding that we are all involved in climate protection together. CARB can provide a template for national and international climate policy by providing equal dividends or shares to all Californians. (CARBONSHARE2)

> **Response:** These comments fall outside the scope of the first 15-day change notice. However, as noted in the Staff Report, we considered all regulatory alternatives, including a carbon fee system and found that cap-and-trade was the best option. As stated in the responses to the 45-day comments, the cap-and-trade regulation has the advantage of an enforceable and declining cap, and will minimize the costs to industry and in turn that will minimize the costs passed through to consumers and lessen any impacts on individuals.

B-11. Comment: EDF supports the Cap and Trade timetables as modified in the 15-day changes, while recommending that the ultimate environmental goal—no more than 1990 levels of emissions by 2020—is not modified. (EDF4)

> **Response**: We acknowledge the comment. Regarding the 2020 emissions target, the proposed modifications do not change the emission reductions goals of the program.

B-12. Comment: ARB must strengthen carbon market oversight provisions, ultimately the best way to ensure market and environmental integrity is to re-evaluate the cap and trade system itself and design it in ways that inherently reduce the opportunities for gaming, fraud, and excessive speculation. The most important step ARB could take to ensuring the environmental effectiveness of AB 32 is to adopt a radically simpler way to price carbon (through a carbon tax, for example) or make the cap and trade program dramatically smaller and simpler. We strongly urge ARB to take the opportunity provided to examine alternatives to cap and trade to implement a robust program to reduce emissions that ensures financial market and environmental integrity and protects the lives and livelihoods of all Californians. (FRIENDSOFEARTH2)

> **Response**: This comment falls outside the scope of the first 15-day change notice. Nevertheless, as discussed in detail in Chapter IV of the Staff Report, staff analyzed a number of alternatives to the regulation, including the carbon tax mentioned by the commenter, and concluded that the cap-and-trade regulation was the best option. Compared to a carbon tax or fee, the cap-and-trade

approach has the advantage of an enforceable and declining cap, and will result in a lower marginal cost of control.

B-13. Comment: This multi-year rulemaking has involved several agencies, hundreds of stakeholders, and numerous workshops and meetings to collectively develop a program that best meets all the policy objectives of AB 32. It would be beneficial to host additional workshops to consider a number of important, complex issues including offset protocols, compliance cycle and penalties, reporting requirements for electricity-deliverers, voluntary renewable energy, long-term electricity contracts, allowance allocation, holding and purchase limits, corporate association reporting requirements, and auction design, market oversight, and penalties. At the public workshop held on July 15, 2011, ARB staff indicated that ARB is considering the release of a second 15-Day Modified Text package for public comment before submitting the Final Statement of Reasons (FSOR) to the Office of Administrative Law by the October 28, 2011 deadline. LADWP supports ARB on this effort and would appreciate an opportunity to review a second 15-Day Modified Text package. LADWP recognizes that the objective of this process is to fine-tune the regulation for clarity and is available to meet with ARB staff to discuss issues related to proposed changes to the regulation to make it workable and enforceable. (LADWP4)

Response: We agree. ARB proposed a second set of 15-day modifications as suggested by the commenter.

Transparency

B-14. Comment: ACMP understands that external forces shorted the public discussion and debate about many details, but ACMP would recommend additional and well-noticed public process as the Regulation is finalized and subsequently modified in future years. As this Regulation is just one of several market-based GHG reduction programs that California has established to achieve its AB 32 goals, ACMP believes that the key to successfully implementing any market-based GHG program, be it Cap and Trade, renewable electricity, Low Carbon Fuel Standard, and/or others, lies within the regulatory details that ensure a transparent, stable, liquid and enforceable marketplace. (ACMP)

Response: We believe that the public process used to develop the regulation provided ample opportunity for public input and discussion. As discussed in Appendix D of the Staff Report, ARB held over 30 public workshops during the development process, and participation was possible at these workshops via webcast. In addition, ARB staff maintained an ARB Public Meetings Webpage, where staff made available all workshop materials and comments posted by stakeholders on program options. As recommended by the commenter, the ARB held additional, well-noticed public workshops in conjunction with two sets of proposed 15-day modifications to finalize the regulatory details and ensure that the regulation is fully developed and tested prior to being implemented. Any future modifications to the cap-and-trade regulation would require a separate rulemaking process using a similar open and transparent public process.

B-15. Comment: ARB must vigilantly use transparency and enforcement tools to make sure that the public interest is protected from the self-dealing, fraud, and windfall profits that have plagued other markets. (SIERRACLUBCA5)

Response: This comment falls outside the scope of the first 15-day change notice. Nevertheless, ARB agrees on the need to ensure that the program contains sufficient safeguards to ensure integrity.

B-16. Comment: To garner support, the Cap and Trade program requires greater public awareness and understanding than currently exists. While CARB has been fully transparent, the use of jargon and highly technical language makes it difficult for even the somewhat knowledgeable citizen to comprehend the various proposals. I would encourage the use of Executive Summaries and other forms of communication that make the proposed changes more easily understood. (TVRP)

Response: This comment falls outside the scope of the first 15-day change notice. However, ARB agrees on the need to ensure that the program contains sufficient safeguards to ensure integrity. A number of definitions were added or modified to improve clarity and to ensure that the terms used in this regulation are consistent with those used in the mandatory reporting of GHG emissions regulation. The proposed cap-and-trade regulation package also contains an executive summary and general overview of the proposed cap-and-trade program. Additionally, fact sheets and user friendly handouts such as workshop presentations are posted on the cap-and-trade website.

District Role

B-17. (multiple comments)
Comment: In the adopting Resolution for the Hearing in December of 2010, the ARB Board directed the Executive Officer to establish a venue, facilitated by a Board Member, to resolve implementation concerns with CAPCOA (see page 13 of the Resolution). We are disheartened to report that the "Board-member facilitated dialogue" has not been convened. CAPCOA has made several attempts to schedule a meeting to initiate the dialogue. In early May, Mr. Goldstene met with the CAPCOA Board and requested a delay to allow staff the opportunity to work with CAPCOA on our concerns. Unfortunately, no meaningful discussions have been held (ARB staff requested a conference call with a small group of CAPCOA members to ensure we understood the Cap and Trade program, and Mr. Goldstene and staff have briefed the CAPCOA Board on ARB's progress on this rulemaking and several other programs). At the same time, the 15-day changes do not address a number of our concerns, nor do they leave any room for them to be addressed in the future. We believe the facilitated dialogue could have helped to resolve this before the matter came before the ARB Board a second time, and we still believe it will be critical going forward. We respectfully request that

the Board urge that this process get under way expeditiously, and that language be included in the Cap and Trade rule to allow the implementation of any future agreements. (CAPCOA3)

Comment: CAPCOA reiterates the considerable value local air districts can add to the climate program when ARB recognizes our role as co-regulators in this process, rather than considering us interested stakeholders. Local districts have decades of real-world expertise in evaluating, permitting, collecting and verifying emissions inventories from, and enforcing requirements on, the stationary sources subject to the Cap and Trade and Mandatory Reporting rules. This includes requirements related to Cap and Trade programs on the national and regional level, credit banking, and offset evaluation. This expertise has been hard-won, and with it has come a clearer understanding of the potential pitfalls and mistakes that can arise in early program development, and also how to structure programs to ensure the best compliance, and overall program performance. Our success has secured substantial reductions in ozone precursors, sulfur oxides, and particulate matter, as well as regional exposures to toxic air contaminants and smoke from open burning. CAPCOA and its members continue to offer this expertise to ARB as it develops and implements the rules for the Cap and Trade program, as well as other climate protection rules. We continue to object to program provisions that restrict district actions, and imply that air districts have a profit or other motive in participating in any program, beyond the common objective we share with ARB to achieve emission reductions and ensure the proper and successful implementation of the program. (CAPCOA3)

Comment: SCAQMD and CAPCOA have consistently raised several issues regarding how local air districts can help facilitate compliance for AB 32 requirements and the appropriate roles and responsibilities for air district participation. These items remain unresolved. The CARB adopting Resolution for the December 2010 public hearing included a provision that the Board directs the Executive Officer to establish a Board member facilitated dialogue with the California Air Pollution Control Officers Association regarding involvement of the air pollution control and air quality management districts (air districts) in the implementation of the Cap and Trade Regulation, development of compliance offset protocols, and other AB 32 programs. Unfortunately, this process has not occurred. (SCAQMD4)

> **Response**: These comments fall outside the scope of the first 15-day change notice. Nevertheless, we intend to initiate a dialogue with CAPCOA as directed by the Board in Resolution 10-42.

B-18. Comment: The proposed rules do not address the ability for air districts to perform multiple roles in the cap-and-trade program. Section 95986(d)(3) still contains restrictions that an organization cannot perform multiple roles. Add section 95989 as follows:

> California air pollution control districts or air quality management districts
> Notwithstanding any other provision of this regulation, California air pollution

control districts or air quality management districts may be approved for multiple roles, including verification for mandatory reporting or offsets, holding compliance instruments, implementing offset projects that are verified by a third party and approved by CARB, and running a Registry, provided the appropriate training, certification, or approvals are obtained from CARB. Decisions on such approval requests will be provided in a timely fashion. (SCAQMD4)

Response: We believe it is not necessary to add section 95989. The cap-and-trade regulation provides for distinct roles within the compliance offset program. The roles include project developers, offset verifiers, and approved offset project registries. There is a clear separation of roles for offset project developers, verifiers, and registries to keep in place a system of independent checks and balances throughout the whole offset system. It will be important for air districts to decide which role(s) they would like to play in the compliance offset program. Currently, air districts are allowed to develop offset projects using ARB compliance offset protocols and then have those reductions subject to an independent review by an ARB-accredited verifier.

Working Group/Advisory Group

B-19. (multiple comments)
Comment: CLFP supports and encourages a stakeholder advisory committee to provide continual and thoughtful feedback to CARB as the program rolls out during the next few years. (CALFP3, AB32IG2)

Comment: CMTA supports the development of an industry stakeholder advisory committee to provide continual and thoughtful feedback to the CARB Board for its consideration as the program rolls out during the next few years. (CMTA3)

Comment: We urge CARB to include a periodic review process of the Cap and Trade program via a stakeholder advisory group to ensure emission reductions goals are being met in a manner that is both economically efficient and environmentally sound. Periodic reviews should include impact assessments of a California only program to ensure that it meets the economic and emission reduction goals under AB 32. While ensuring GHG goals is important, it is equally important that consideration and oversight be given to any and all economic impacts, including those industries that would be both directly and indirectly impacted as a result of economic leakage. As CARB moves forward, we hope that these and other important issues are addressed with much diligence and oversight via an open forum that allows for public participation and comment in order to ensure transparency in the process and maintain integrity in the program. (CALCHAMBER3)

Comment: We support and encourage a stakeholder advisory committee to provide continual and thoughtful feedback to CARB as the program rolls out during the next few years. This committee should include representatives from capped industries as well as representatives from the agricultural sector. (CCGG2)

Comment: The District continues to support the ongoing operation of a Cap and Trade Implementation Working Group with CARB and air districts. Such a working partnership between CARB and the air district staff will help ensure the success of the Cap and Trade program. (BAAQMD3)

> **Response**: These comments fall outside the scope of the first 15-day change notice. Nevertheless, we agree that we need to carefully monitor industry progress toward compliance with the regulation, as well as the operation of the markets, although we do not necessarily see the need for the specific stakeholder committees or working groups suggested by the commenters. As specified in Board Resolution 10-42 for the original regulation, the Board directed the EO to hold public consultations to identify potential obstacles to compliance and, as necessary, incorporate or enhance compliance assistance mechanisms into the program. ARB fully expects to continue its dialogue with stakeholders and will continue to evaluate the program.

Implementation

B-20. Comment: The ARB proposal has not adequately defined many of the tools (i.e., forms, registrations, procedures, software) required for a Cap and Trade program (even one with the proposed “soft start” in 2012). Hence, a smooth and efficient start of the program is uncertain. If development of appropriate tools is further deferred, efficient functioning of the program could be put in jeopardy. WSPA recommends that where ARB has identified specific dates for program implementation, but that will require ARB tools (such as registration forms) for successful implementation, those dates should be deleted and a timeframe instead be defined. For example, instead of saying the registration is required on January 1, 2012, the Regulation should say, registration is required 30 days after ARB publishes (releases) the registration tools. Further, WSPA recommends that ARB develop a schedule for development procedures and requirements associated with the Cap and Trade program to allow interested parties to develop their approaches in line with ARB concepts. This collaborative process will facilitate involvement by stakeholders and ensure broad input into details required by the Cap and Trade program. (WSPA3)

> **Response:** Many of the 'tools' listed in the comment are part of program implementation and do not have to be included in the regulation itself. As components of the infrastructure become operational, we are committed to having stakeholders provide feedback on the design and recommend improvements. We included specific deadlines in the regulation to ensure that the regulation is enforceable. The compliance start date was moved from 2012 to 2013 to ensure that all the regulatory elements are in place and fully functional. We have initiated activities to develop the necessary rule implementation infrastructure for the regulation, including a market tracking system to trade allowances and offsets; contracts for an auction services provider; a financial services provider; and a market monitor. We are also

committed to providing continual public updates, with opportunity for stakeholder comment, on the implementation of the regulation.

Program Monitoring

B-21. (multiple comments)
Comment: Establish a work plan to ensure that the tools, guidance, training, market tests, and infrastructure that are necessary to comply with the regulation are in place before requiring entities to comply with the requirements. CCEEB recommends that:

1) The ARB develop a work plan with a clear list of tools, guidance, policies, trainings, and systems that they must develop, along with completion deadlines for each activity that must be in place for the regulated entities to comply.
2) The ARB include a mechanism that links an entity's compliance deadlines directly to availability of theses compliance tools, allowing for sufficient lead time for facility compliance.
3) The ARB should release a "formal declaration of readiness" at least 60 or 90 days prior to "going live" with their first auction. The CAISO for the Market Redesign and Technology Upgrade underwent this process including system testing by market participants and CAISO ran into some software problems. It is important for ARB to have the same type of formal action to notify market participants'. Furthermore, this declaration would be an opportunity for stakeholders to raise to ARB's attention any concerns they may have about the status of the program and readiness to go live.

Additionally, ARB should clearly announce the full schedule from now to the end of this rulemaking in October 2011. (CCEEB)

Comment: EDF supports CARB's proposal to establish market monitoring and oversight committee(s) as an essential element for public confidence in the program. In addition to detecting, responding to, and preventing activities (such as price manipulation and fraud) that can undermine the efficacy and public trust in the program, EDF recommends CARB vest the committee(s) with a broad range of important responsibilities to ensure the overall program is working as designed. While EDF recognizes that some of these responsibilities may be undertaken by CARB staff, market oversight and monitoring committee(s) will be steeped in information associated with market operations and trends, and will therefore be a valuable source of information. We urge CARB to make sure the committee(s) have adequate staff support and a clear delineation of responsibilities throughout their existence. There are responsibilities the market monitoring and oversight committee(s) should take on, including, but not limited to the following:

- Evaluating leakage risks and assumptions used to determine free allowance allocation quantities for protection of trade-exposed energy intensive industries. At a minimum, the overall evaluation of risk and the degree of protection needed to ameliorate it should be revisited prior to the start of the second program compliance period.
- Evaluating whether windfall profits are being generated due to the current allowance allocation structure and performance benchmarks used as the basis

for allocation calculations within individual industry classes. While CARB has stated that benchmarks will remain unchanged through the course of the program, it is important to be at least open to revisiting benchmarks that are causing perverse consequences. One example of a potential consequence of concern is an overly generous benchmark for heavy crude oil that may lead to increased processing of dirtier feed stocks.

- Evaluating whether existing regulatory provisions for offset liability (in the case of credit invalidation or reversals) are causing unintended consequences on the development and availability of offset project credits within the AB32 cap-and-trade market. Such impacts may arise if, for example, third party mechanisms for insurance or liability relief are not developed or are unnecessarily expensive. Additionally, the committee(s) should evaluate whether other barriers to market access exist for project developers that do not further environmental integrity or program rigor.
- Coordinating with CARB staff responsible for implementing the cap-and-trade adaptive management strategy to inform staff of emerging or existing monitoring conditions that are indicators of potential or observed impacts on environmental quality. (EDF4)

Comment: Incorporate provisions to a) establish monitoring indicators and criteria for changing the program based on the indicators by June 2012 and b) overall program review of the Cap and Trade Regulation by March 2014 and in March 2017. The Cap and Trade program touches the majority of California's economy. A well designed Cap and Trade can achieve significant GHG reductions and drive innovations but design flaws in a Cap and Trade program could cause significant economic and/or environmental damage. There are many elements in this Cap and Trade Regulation that have not been tested by other cap and trade programs. To ensure that we are able to detect any problems early and take corrective action promptly, Shell believes it is critical that key indicators of both a) market operations and b) California's energy and economic health be identified and monitored routinely. A provision should be added to the Regulation requiring that these indicators and the criteria for any changes that may be driven by the analyses of these indicators be clearly established by June 2012. Such criteria are essential to provide businesses with certainty on what conditions, how and when the Regulations may be changed. Shell additionally believes that a provision should be included requiring an overall program review of the Cap and Trade Regulation to be completed and presented to the ARB Board by March 2014 and in March 2017. (SHELLOIL)

Response: This comment falls outside the scope of the first 15-day change notice. Nevertheless, we agree that we need to carefully monitor industry progress toward compliance with the regulation, as well as the operation of the markets. Mechanisms are in place to do this, although not exactly as recommended by the commenters. As specified in Board Resolution 10-42, the Board directed the EO to hold public consultations to identify potential obstacles to compliance and, as necessary, incorporate or enhance compliance assistance mechanisms into the program. The Board also directed the Executive Officer to contract with an independent entity with appropriate expertise that will monitor and provide public reports on the operation of the market, including auctions and reserve sales, on a quarterly basis and recommend appropriate action, which could include taking corrective action prior to the next auction, adding future allowances to the allowance reserve or future auctions, or temporarily suspending trading in the market.

Adaptive Management

B-22. (multiple comments)
Comment: The adaptive management strategy should be in place no later than when facilities begin taking action to meet compliance obligations under the program. For an adaptive management strategy to be effective, it should enable an agency to respond to conditions when and if they arise, and with as much forethought and deliberation as practicable. Accordingly, in putting together the strategy, the agency should have already performed scenario assessment and identified steps of action based on likely scenario outcomes. When applied to the California Cap and Trade rule, having an adaptive management strategy in place when needed means that it should be in place when covered facilities begin taking actions to meet compliance obligations (buying and trading permits, making reductions, etc.) under the program. (EDF5)

Comment: TWS recommends the development of an adaptive management system to monitor and mitigate any adverse impacts on the forest sector. Tools that allow accurate assessment of the state of forest carbon and the health and resiliency of forest ecosystems within California are essential to assessing the effectiveness and impacts of California climate policies affecting forests. Public engagement in the development of these measurement systems will help ensure that the assumptions, inputs, and methodologies used in these systems are rigorously vetted and widely supported. The Cap and Trade Regulation should include provisions for periodic review and revision of the Regulation in light of any potential adverse or unintended impacts caused by provisions of the Cap and Trade program such as the provisions in the Cap and Trade program governing offsets or biomass. (TWS)

Comment: CARB's current approach to adaptive management of the AB 32 Cap and Trade program needs more detail and commitment. The program should be focused on a range of environmental impacts, including climate, air and ecosystem impacts, and should be designed to mitigate observed impacts as well as proactively prevent future impacts that are likely to occur. EDF has included specific ideas for the adaptive management program, and we strongly recommend that the program be in place no later than when facilities begin taking action to meet Cap and Trade compliance obligations. (EDF4)

Comment: The current proposal for adaptive management needs more detail and commitment. To date, CARB's provisions related to adaptive management have consisted of references, inferences and statements of actions yet to be taken. More clarity, definition, and concrete action planning for adaptive management is needed. For example, while the AB 32 Scoping Plan, Cap and Trade documents, and agency statements have referenced the need to evaluate and track air quality conditions in environmental justice communities, the compliance methods and permit modifications of regulated entities, and the impacts from use of biomass, no trigger levels for administrative action or evaluation have been identified. These triggers are of critical importance for determining how regulatory compliance options may be affected by the adaptive management strategy, and demonstrating that concerted planning has occurred to protect the overall environmental health from unexpected impacts. Defining triggers now will be important for determining what information must be gathered and evaluated routinely. (EDF5)

Comment: Adaptive management should include a wide range of environmental impacts, such as ecosystem health. Thus far, the approach to adaptive management outlined in CARB's rulemaking documents has been focused primarily on the potential for localized air quality impacts to be caused by the program. We urge CARB to expand their adaptive management focus to other environmental factors, such as the potential ecosystem impacts. Specifically, how to adaptively manage biomass and the potential impact of treating biomass combustion as carbon neutral. We submit this comment to memorialize the recommendation for managing biomass combustion, and to ensure the commitment to ecosystem impact response planning is retained. (EDF5)

Comment: Adaptive management should include responsive and proactive action planning. Within the discussion documents related to adaptive management released thus far, CARB has identified a need to respond to observed environmental conditions caused by the cap-and-trade program. While this reactive action planning is essential, it is not the full picture of necessary adaptive management. We also recommend that CARB's adaptive management strategy can and should incorporate indicators of potential future changes to environmental quality caused by the program, thereby allowing the program to be both responsive as well as proactive in ensuring the environmental integrity (and statutory compliance) of the program. (EDF5)

> **Response:** This comment falls outside the scope of the first 15-day change notice. Nevertheless, as stated in the responses to the 45-day comments, we are committed to develop an adaptive management approach to address any potential adverse environmental impacts associated with potential localized air quality impacts and the U.S. forest offset protocol. In addition, we will monitor the implementation of the cap-and-trade regulation and will develop appropriate responses to rectify any identified issues. The adaptive management approach will allow us to develop the appropriate tools to determine if there are impacts due to compliance with the cap-and-trade regulation as information becomes available.

B-23. (multiple comments)
Comment: We recommend the identification of indicators and impact trigger levels that are useful to determine whether forest biomass stocking changes or ecosystem health impacts are occurring due to the treatment of biomass as a carbon neutral fuel source (see NGO letter on biomass dated April 8, 2011). (EDF5)

Comment: We recommend the identification of steps that can be taken, established as a hierarchy of action, for preventative and responsive action planning to respond to observed forest biomass stocking changes or negative ecosystem health impacts. (EDF5)

> **Response:** This comment falls outside the scope of the first 15-day changes to the regulation. The commenter is correct that biomass-derived fuels are exempt from a compliance obligation since CO_2 emissions resulting from the combustion of biomass are considered biogenic. However, we will not use an adaptive management approach for forest biomass. The cap-and-trade FED did not identify potential adverse environmental impacts associated with increased use of forest biomass as a result of the cap-and-trade regulation. Separately, we include an adaptive management approach in the cap-and-trade program to address any potential adverse environmental impacts associated with potential localized air quality impacts and the U.S. forest offset protocol. We will, however, monitor the impact of the cap-and-trade regulation and other ARB and state policies on forest biomass.
>
> In addition, the updated economic evaluation of California's climate change scoping plan did not indicate that the use of biomass would increase in response to the proposed regulation. Increased use of biomass is already incentivized by existing regulations such as the renewables portfolio standards (RPS) and the low-carbon fuel standard. The RPS requires publicly owned utilities to obtain 33 percent of their energy from renewable resources, including biomass. Most utilities are challenged to achieve the renewable target despite the availability of biomass as a renewable fuel. Increased use of biomass for energy generation created by other state policies and initiatives, such as the Renewable Portfolio Standard, is discussed in the cap-and-trade FED (see pages 351-352).

Delay Action

B-24. (multiple comments)
Comment: It is critical that the Cap and Trade market features and systems be adequately structured and tested in order to avoid possible catastrophic consequences similar to the 2001 energy crisis. Thus, SCE strongly supports the one-year delay of the compliance elements of the Cap and Trade program. This delay will allow additional time for ARB to improve its market structure, test its systems, and create stronger protections against market manipulation while maintaining the environmental integrity and important leadership position of this program. (SCE3)

Comment: Ag Council appreciates ARB's decision to delay implementation of Cap and Trade for one year. There are many outstanding issues with this regulation that we continue to work on, and given these unanswered questions, the delay in implementation is appreciated by our membership. (ACC4)

> **Response**: This comment falls outside the scope of the first 15-day change notice. Nevertheless, we believe that beginning enforcement of the compliance obligation in 2013 will allow us to address outstanding issues and ensure that the market tracking system is developed and tested before moving into the first year of compliance.

Economic Harm/Burden

B-25. Comment: We ask that the costs of the program to regulated entities continue to be updated as the program moves along. Economic impacts to labor, especially in the rural communities where agricultural production is a major employer, needs to be highlighted. (CCGG2)

> **Response:** This comment falls outside the scope of the first 15-day change notice. Nevertheless, as stated in the responses to the 45-day comments, we are committed to regular reviews of the implementation of the regulation, periodic updates to the Board, and proposed modifications to the regulation, as needed. As discussed in Board Resolution 10-42, the Board directed the Executive Officer to update the Board annually on the status of the cap-and-trade program. We believe the broad language in the Resolution provides for reports to the Board on any issues of concern, including costs to rural communities.

B-26. Comment: A Cap and Trade system that distinguishes emissions from different sectors for differential treatment does not result in market consistency, does not equitably distribute economic burden and opportunity, and is a serious violation of the intent of a Cap and Trade program. This is the case when it comes to the Regulation's treatment of the electricity sector—with the most egregious example being the use of auction revenue to mitigate the price impact of carbon costs in this sector—and in this sector only. A clear example of the market distortion created by this inequity is a consumer faced with the choice of running a device, appliance or vehicle on either electricity or another fuel (i.e. diesel, gasoline, natural gas). All other factors being equal (including the carbon intensity of the chosen fuel), the choice to operate the device, appliance or vehicle on electricity will be influenced by the fact that the use of electricity comes with a monthly rebate check (or other mechanism to mitigate the cost of electricity), while the use of other fuels will not. This is a clear and unacceptable market distortion and a divergence from the intent of a cap and trade system. This picking of winners and losers distorts the effect of decisions that actually should influence energy choices and consumption. This market distortion could cause a consumer to choose to purchase an electric device, appliance or vehicle rather than a lower carbon alternative—and in doing so maintain energy demand and carbon emissions at existing levels. Emissions and consumers must be treated equally in order to provide the proper incentive for reductions and for energy consumption choices. In order for the cap and trade program to be successful and equitable, the criteria for allocation must be consistent amongst sectors—and the use of auction revenue should not result in arbitrary, differential price signals amongst energy types. (BP2)

> **Response**: This comment falls outside the scope of the first 15-day change notice. Nevertheless, as stated in the responses to the 45-day package comments, we considered cross-sector equity issues when developing the regulation. We believe that the costs of cap-and-trade are equitably distributed through the overall approach.

Cap/Allowance Budget

B-27. (multiple comments)
Comment: PG&E requests further clarification and examination of the Cap and Trade program's allowance budget for the year 2020 as established in section 95841. The Scoping Plan issued December 2008 included a preliminary estimate of 365 million metric tons (MMT). The Cap and Trade proposed Regulation proposes a substantially lower allowance budget of 334.2 MMT. This substantial downward adjustment also appears to reduce the allowance budget for many years prior to 2020. ARB has not provided support for this significant downward adjustment. (PGE4)

Comment: The 2013 first year compliance budget should be 165.8 million allowances. By reducing the year one compliance budget to 162.8 million allowances, ARB is essentially requiring reductions of 3.0 million allowances prior to the new compliance obligation start date. Under the summary of proposed modifications, ARB is requesting comment on which program elements should begin in 2012 and what advantages there are to phasing in various components during 2012. Since section 95840 proposes the extension of the first compliance period start date, the associated compliance budget should be adjusted to accurately reflect this delay. (VALERO2)

Comment: CCEEB is concerned that the cap in this regulation exceeds previously defined scoping plan levels, driving the program reductions below 1990 emissions levels. This is particularly evident given the new 2010 emissions levels that are roughly half of the projected emissions for 2012. CCEEB recommends that ARB clearly articulate the rational for this increased compliance obligation and the reasons why the emission estimates are higher when the economy, production, and business are down, and reconcile this data with the updated GHG forecast and the recent Legislative Analyst Office analysis. (CCEEB3)

> **Response**: These comments fall outside the scope of the first 15-day change notice. Nevertheless, as stated in the responses to the 45-day comments, the main difference between the estimated cap of 365 $MMTCO_2e$ in the Scoping Plan and the 334 $MMTCO_2e$ cap in the regulation is that the Scoping Plan estimate was based on entire sectors. It did not consider sources that are not addressed by the regulation or certain types of transportation fuels that are used in small quantities. In section 95841 of the regulation, we incorporated an improved approach of estimating the allowance budgets. The starting allowance budget is equal to the expected emissions for the initial year that a covered entity enters the cap-and-trade program. The adjustment to the allowance budget was made using 2008 facility-level data gathered through the mandatory reporting

program that improved emissions estimates for the covered entities. Using these improved estimates, we calculated a new broad-scope 2020 allowance budget of 334 $MMTCO_2e$.

Duplicative Regulations

B-28. Comment: CCEEB is concerned that California businesses will be subject to duplicative GHG regulations from the State and federal government. Although it is unlikely that a federal Cap and Trade regulation will be forthcoming in the near term, EPA has been working to develop GHG regulations such as GHG BACT and NSPS. Compliance with duplicative regulations will be costly and will not result in material benefit toward our GHG reduction goals. CCEEB recommends that ARB clearly state its intent to not subject California's businesses to duplicative GHG regulations. (CCEEB3)

Response: This comment falls outside the scope of the first 15-day change notice. Nevertheless, we recognize the importance of harmonization between State and federal GHG emissions reduction requirements. As stated in Board Resolution 10-42, the Board directed the EO to work with U.S. EPA on the development of a federal regulatory framework to grant delegation or equivalency to California’s climate change program where appropriate. Additionally, our mandatory GHG reporting rule is comparable to the U.S. EPA mandatory reporting rule. In the event the U.S. EPA cap-and-trade program becomes available, our cap-and-trade program design element can easily transit into the U.S. EPA program.

Periodic Review

B-29. Comment: Given the importance and complexity of the Cap and Trade Regulation, and the fact that it has never been done to this degree anywhere in the world, we strongly support inclusion, in the Regulation, of a required periodic review of the, similar to the concept included in the Low Carbon Fuel Standard Regulation. The scope of each review should include, at a minimum, consideration of the following areas:

- Trade exposure
- Progress toward linkage
- Offset supply
- Status of allowance reserve
- Leakage
- Carbon price in direct regulations
- Market liquidity and Allowance
- Status of cap and trade programs in other states
- Auction process
- Carbon price volatility
- Progress toward 2020 goal
- Benchmarking

- Market operations
- Market manipulation
- Treatment of transportation fuels in the Cap and Trade program
- Treatment of imported electricity and effect on power markets
- Evaluation pass through of carbon costs by generators who must hold allowances but are not allocated allowances
- Evaluation of cross sector inequities in sharing the burden of carbon costs, including equal carbon cost mitigation across sectors were that occurs
- Effect on energy prices—gasoline, diesel, electricity, natural gas
- Effect on employment in the State (BP2)

  Response: This comment falls outside the scope of the first 15-day change notice. Nevertheless, we agree that periodic reports should be provided to the Board on the operation of the cap-and-trade program. As discussed in Board Resolution 10-42, the Board directed the EO to update the Board annually on the status of the cap-and-trade program. While the resolution language does not specifically mention all of the specific areas suggested by the commenter, we believe the broad language in the resolution provides for reports to the Board on any issues of concern. We plan to do overall program monitoring of the cap-and-trade regulation.

Sectors/Facilities/Alternative Fuels

B-30. Comment: ARB should add text about Liquid Fluoride Thorium Reactors (LFTR), and spend time talking about them too. They must be considered. California imports electricity from Nevada, which uses coal in its production. We also use lots of Natural Gas in California. Coal and natural gas produce a huge amount of CO_2. Liquid Fluoride Thorium Reactors produce none, and are a cheaper source of electricity. Check out this web site and watch the first video: http://www.thoriumenergyalliance.com/ThoriumSite/portal.html. Also, we can use up all our spent nuclear fuel in LFTRs, also called Molten Salt Reactors. We need to get research and development going, build some, and convert our nuclear reactors to LFTRs. LFTRs are much safer, more efficient, less expensive, and far more immune to human errors than other kinds of nuclear reactors. LFTRs are scalable so small ones, can be located all over the USA, which reduces transmission lines losses. Thorium is much safer, cheaper and plentiful than uranium. Thorium can be safely transported. Let California lead the country by having the first working LFTR since the one that ran at Oak Ridge National Labs in Tennessee in the 1960's. (TEA)

> **Response**: This comment falls outside the scope of the first 15-day change notice. Nuclear power does not emit GHG emissions, and is not addressed by this regulation.

High Global Warming Potential Gases

B-31. Comment: Covered gases for the Cap and Trade Regulation currently include SF_6 and other fluorinated gases. However, high Global Warming Potential (GWP) gases are regulated separately from the Cap and Trade program under the AB 32 Scoping Plan and should not be included as covered gases in the Cap and Trade Regulation. Although they are typically included in the definition of "CO_2e" (or carbon dioxide equivalent), these fluorinated gases are not reported under the MRR, and therefore would not carry a compliance obligation under the Cap and Trade program. Modify section 95810 as follows:

> This article applies to the following greenhouse gases: carbon dioxide (CO_2), methane(CH_4), nitrous oxide (N_2O)~~, sulfur hexafluoride (SF6), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), nitrogen trifluoride (NF3), and other fluorinated greenhouse gases~~. (LADWP4)
>
> **Response**: This comment falls outside the scope of the first 15-day changes to the regulation. Nevertheless, we disagree with the comment. As stated in the Staff Report, to maximize GHG reductions, the program will include emissions of carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), sulfur hexafluoride (SF_6), and nitrogen trifluoride (NF_3).

Energy Audits

B-32. (multiple comments)
Comment: CARB has proposed that industrial audits may form the basis of command and control regulations for emissions now covered by the Cap and Trade program. The industrial audit was not included in the scoping plan for this purpose, and such a purpose directly conflicts with the cost-minimization purpose of the cap-and-trade program. This proposal will reduce operational flexibility and increase costs and should be rejected. (CMTA3)

Comment: CARB should discontinue any consideration of mandatory energy efficiency standards and only consider options in the future after the results from the Cap and Trade program are evaluated. CARB has recently commented that it will consider rulemaking next year to mandate energy efficiency projects. This directly conflicts with the flexibility promised by the cap-and-trade program and our ability to control cost impacts on our customers. (CONOCO2)

Comments: IEP opposes mandating reductions or efficiency improvements contemplated under the audit regulation. CARB should not mandate reductions or efficiency improvements contemplated in the Audit Regulation on top of cap and trade requirements. (IEPA2)

Comment: ARB invited comment on its proposal to require identified low cost onsite reductions at large industrial sites, pursuant to the energy efficiency assessments required under the Energy Efficiency and Co-Benefits Assessment for Large Industrial Sources Regulation. The CCC is opposed to such a requirement and argues that the design of the Cap and Trade Regulations (declining cap and increasing cost per ton of carbon over time) incents large industrial sources to take cost-effective actions to reduce carbon emissions. The assessment required under this Regulation will no doubt help to identify improvement projects, but the Operators of these facilities are best qualified to determine the most cost-effective way to reduce emissions. A Cap and Trade program should set the performance standard, and then allow the market to determine how best to achieve the goals. This extra layer of "command and control" defeats the purpose of such a market mechanism as Cap and Trade. (CACC2)

Comment: Mandating GHG emission reduction projects in response to the energy audits raises problems similar to the industrial sector and electric sector allowance allocation issues. The original July 25, 2011, notice for the cap-and-trade regulation reiterates that staff continues to evaluate the manner in which the Energy Audits required by regulation for many of California's largest emitting sources will be translated into specific, mandated emission reduction actions. Subsequently CARB indicated that this issue will be addressed later through a subsequent process. ACE is very concerned with the potential for mandated programs to carry the same problem for facilities with existing contracts as does the overall cap-and-trade program: i.e., facilities with existing standard QF contracts have no way to recover the costs of the mandated programs unless and until the industrial steam hosts and the IOUs agree to contract modifications and execute revised contracts with pass through cost language. Therefore, any implementation of mandated actions as a result of the Energy Audits must also address the need for some sort of specific direct assistance if the steam hosts and/or IOU remain unwilling or unable to enter into renegotiated contracts. (ACERIO)

Comment: The costs of mandated GHG emission reduction projects in response to the energy audits will compete with capital required to comply with the cap-and-trade program. ACE fundamentally believes that any "one size fits all" approach will ultimately undermine the success of the cap-and-trade program, and should therefore be completely avoided. The Energy Audit began as a tool for CARB staff to assess the type of actions that CHP/QF and industrial facility owners might take to reduce emissions; transforming that data into mandated actions is an unwarranted interference in the market-based cap-and-trade program that will likely be counterproductive and could very likely lead to "leakage" in all industry sectors. (ACERIO)

> **Response**: The rulemaking effort to ensure that large industrial sources subject to the Energy Efficiency and Co-Benefits Assessment Regulation be required to take all cost-effective actions identified under those assessments will be a rulemaking process separate from this one. ARB plans to initiate a separate regulatory process in fall 2011 to discuss metrics and action to implement this commitment. At that time, we will also address the concerns and comments noted by the commenters. This future public process is the appropriate forum for discussion of the reductions in flexibility and cost control due to mandates.

Transportation Fuels

B-33. (multiple comments)
Comment: Transportation emissions should be considered in the Cap and Trade program only if a formal review determines that this action is necessary and implementation would be more cost-effective than other policy approaches in achieving GHG reduction from the sector. If it is determined necessary to include emissions from the consumer use of transportation fuels in the Cap and Trade system, the program should be designed to create a clear carbon price signal for consumers, reduce obligated party exposure to allowance price volatility with respect to the consumer compliance obligation, and help companies manage working capital requirements associated with the consumer emissions compliance obligation. (CONOCO2)

Comment: ConocoPhillips has considered various options for managing transportation fuel emissions in a Cap and Trade program. We believe a fixed price allowance program as outlined below could address some of the identified concerns:

- The State would set aside the volume of allowances necessary to cover transportation consumer emissions from use of gasoline and diesel fuel.
- The State would establish a price for those allowances based on some average of recent allowance market prices. That price would be adjusted periodically.
- Only obligated fuel providers could purchase the set-aside allowances at the established price noted above.

The program would also have the added benefit of reducing unnecessary administrative burden while still achieving the intended program goals. Stationary source emissions from the refining sector and other covered entities should not qualify for this set purchase price program. (CONOCO2)

Comment: CMTA is concerned about the impact of including transportation fuels under the cap beginning in 2015. The Scoping Plan proposed inclusion of transportation fuels in the cap-and-trade program beginning in 2015, largely due to the expectation that WCI states would address fuels this way in their state programs. Since California is already implementing the Low Carbon Fuel Standard, and no WCI states are prepared to link to California's Cap and Trade rule, we recommend that the leakage impacts of a California-only fuels-under-the-cap (on top of the LCFS) be studied and that a decision with regard to the treatment of transportation fuels under Cap and Trade be postponed pending that analysis. (CMTA)

Comment: WSPA continues to oppose ARB's proposal to include fuels under Cap and Trade in 2015 because there are too many unanswered questions about how this system will operate, both initially (during the first 2-year period) and in subsequent years when fuels are categorically included within the Cap and Trade program starting in 2015. We have previously asked ARB to study issues and alternatives relating to inclusion of fuels within a Cap and Trade program before finalizing a decision whether to include fuels within this program. In addition, WSPA has highlighted a number of issues related to reporting and verification of product data reporting in the Mandatory

Reporting Regulation that will require further discussion and evaluation. WSPA recommends that for this regulatory package, ARB defer inclusion of fuels within a Cap and Trade program until a thorough study of the alternatives to inclusion as well as the economic and environmental implications of possible ARB actions are clearly defined. In order for that study to be completed and reviewed, at a minimum, ARB should defer inclusion of Fuels within a Cap and Trade program until the onset of the 3rd compliance period in 2018. (WSPA3)

Comment: Fuels should not be included under the cap due to excessive costs to the consumer and business and the inequities created between industries. Placing fuels under the cap will place a high financial burden on providers and/or users of propane, gasoline and distillate fuel in California that may delay or defeat economic recovery for the state. Emissions from consumer use of these products results in about 170 million tonnes/yr of emissions. At the minimum auction price of $10/tonne, this burden would equate to approximately $0.10 per gallon or approximately $1.5 to $2.0 billion per year. California gasoline taxes are the fourth highest of any state in the US and about 40 percent higher than the national average. California diesel taxes are the highest in the nation; specifically 55 percent higher than the national average. Though California's population has grown slightly during recent years (due to foreign immigration and births), more people have left California for other states than have moved here. Cost of living is frequently cited as a primary reason for citizens and businesses leaving the state. This cost burden of including fuels under the cap is not only excessive it creates inequity in the Regulations between industry that additionally impact consumers and businesses. Power generation and imports result in approximately 90 million tonnes/yr of CO_2e emissions, yet free allowances to the utilities will offset an estimated 94 percent of the cost of carbon over the life of the program. No allowances are proposed for producers or consumers of fuel. Including fuels under the cap is redundant with the low carbon fuel standard and vehicle mileage standards. Also, as presently structured, treatment of fuels under the cap is inequitable relative to treatment of utility power. The cost to producers and/or consumers of fuels will be excessive. (TESORO2)

Comment: Transportation fuels should not be subject to the Cap and Trade program. The inclusion of transportation fuels under the Cap and Trade program will have profound financial impact on the State of California. As one of the single largest forms of energy subject to Cap and Trade, the refining industry will purchase billions of dollars of allowances to cover fuel emissions. The consumer will bear this steep financial penalty while the State will recover these funds and reap the benefits. The goal of reducing GHG emissions will only manifest itself through reduced fuel consumption brought about by price increases—a result no different than applying carbon taxes. We strongly urge CARB to abandon this approach of regulating transportation fuel GHG emissions. To the extent that CARB continues to treat transportation fuels as part of the carbon management portfolio, we request that CARB more fully consider a carbon tax on fuels as this market mechanism will eliminate much of the complexity, variability, and bureaucracy that accompany a Cap and Trade program. (VALERO2)

Comment: CARB should not extend the Cap and Trade program to consumer emissions from use of transportation fuels. This element of the program is a clear overlap of the federal Renewable Fuels Standard and the State LCFS programs. Adding the enormous burden of consumer carbon emissions due to fuel combustion to California's Cap and Trade program will overrun the program's capabilities and could compromise its success. The probable step-change in consumer product costs to cover this additive element for gasoline and diesel would only escalate leakage of jobs and businesses that rely on petroleum products. Instead, CARB should allow existing Federal programs to address GHG emissions in this sector. This is consistent with the approach adopted in the European Union. (CONOCO2)

Comment: We believe treatment of fuels-under-the-cap issue needs to be revisited. The Scoping Plan proposed inclusion of transportation fuels in the cap-and-trade program beginning in 2015, largely due to the expectation that Western Climate Initiative states would address fuels this way in their state programs. Since California is already implementing the Low Carbon Fuel Standard, and no WCI states are prepared to link to California, we recommend that the leakage impacts of a California-only fuels-under-the-cap (on top of the LCFS) be re-examined. Since CARB does not intend to implement Fuels under the Cap until the 2015-2017 compliance period, it is important for CARB to take the opportunity now to assess all available alternatives in addressing transportation fuels in a simple and comprehensive framework under AB 32. (AB32IG2)

> **Response**: This comment falls outside the scope of the first 15-day change notice. Nevertheless, we believe that including transportation fuels in the program in 2015 provides a consistent price on GHG pollution throughout the economy and ensures a level playing field across all fuels and consumers. We believe that there are important benefits of including transportation fuels and fuels for residential, commercial, and small industrial users. We also believe that it is appropriate to initially bring these fuels into the program on a reporting-only basis for the first compliance period. This will provide time for ARB and transportation fuel deliverers to work through any issues in the reporting system before they have a compliance obligation beginning in 2015. We will work with our WCI partners and linkage will require a separate rulemaking process where issues would be investigated such as concerns regarding leakage.
>
> If we determine that the cap-and-trade program is not achieving the objectives as defined by AB 32, or if substantial, unanticipated adverse economic or environmental effects are identified (e.g., substantial leakage), we will revise the operation and/or design of the program accordingly. There are also several cost-containment measures that are integrated into the program, including the use of offsets, three-year compliance periods, and the Allowance Price Containment Reserve.

Low Carbon Fuel Standard (LCFS)

B-34. Comment: Section 95820 authorizes ARB to issue GHG allowances and offset credits as compliance instruments that is an authorization to emit a ton of CO_2e GHG.

WSPA believes that compliance instruments from a cap-and-trade program should be eligible for compliance in other programs such as LCFS. WSPA recommends adding a provision allowing compliance to LCFS via transfer of compliance instruments from a Cap and Trade program. (WSPA3)

> **Response:** These comments fall outside the scope of the first 15-day change notice. Currently, to maintain the effectiveness of the program, the LCFS allows the export of LCFS credits to other programs that will accept them, but does not allow importation of credits into the LCFS program. As required by the LCFS regulation, staff is conducting a formal review of the LCFS and may consider assessing credit options in the LCFS program. We do not agree that credits should be used and transferred between the cap-and-trade program and the low carbon fuel standard. They are separate regulations and credits have different definitions in each regulation and are subject to different protocol requirements. The LCFS also looks at carbon intensity while cap-and-trade looks only at actual emissions. There is no direct correlation between the two systems. However, the cap-and-trade program considers any reductions in direct emissions as the result of compliance with LCFS to be recognized and counted as a benefit toward a capped entity's compliance obligation.

B-35. Comment: The high carbon intensity crude oil (HCICO) component of the LCFS regulation disadvantages in-state refinery operations and does nothing to help meet the goals of the AB 32 program. It will likely result in "crude oil shuffling"' and in combination with the full LCFS program lead to loss of high-paying refining and related manufacturing jobs to other states and countries. It also creates immediate competitive advantages for certain in-state producers and refiners of California heavy crudes because these crudes are grandfathered in the program, disadvantages other in-state refineries because they have no crude oil production in the State, and fails to address the fact that refineries outside of the State could process HCICO and then send the partially-refined intermediate or even finished products to California with no potential for enforcement. The HCICO component of the LCFS regulation should be eliminated.
If CARB chooses to proceed, we strongly urge CARB to carefully evaluate and consider the five alternatives (and others) that the LCFS Advisory Committee has described and to work with our industry to carefully evaluate these options and ultimately correct the inequities described. (CONOCO2)

> **Response:** This comment is outside the scope of the 15-day change notice and the proposed changes to the cap-and-trade regulation. The high carbon intensity crude oil (HCICO) component of the LCFS regulation is being addressed in a separate rulemaking related to proposed staff amendments to the LCFS.

Linkage

B-36. (multiple comments)
Comment: PG&E supports linkage to other GHG emissions trading systems as a way to enlarge the Cap and Trade market. PG&E encourages ARB to develop linkage

agreements with other WCI jurisdictions. (PGE4)

Comment: CCEEB recommends expediting linkage and making it a priority to be completed. If linkage is not possible, then CCEEB believes that other cost-containments measures must be adopted to soften the economic impact of this regulation and limit leakage of jobs and emissions. (CCEEB3)

Comment: PG&E believes a well-designed, multi-sector Cap and Trade program linked with emerging regional, national, and international programs will allow California to meet its greenhouse gas (GHG) emission reduction goals in a cost-effective manner as required by AB 32 (Cal. Health and Safety Code, section 38560). While ARB has made progress with the design of the Cap and Trade program, we believe that the program will benefit from additional review and modification based on the input of stakeholders and by engaging an independent market design expert to review the GHG market and its impacts upon energy markets to ensure both are able to function in concert with each other. In this regard, we welcome ARB's decision to defer the start of the cap-and-trade compliance obligation until 2013 to allow necessary testing of auction systems, design and protocols in the first half of 2012. It is critical to test the robustness of the auction systems, design, and protocols through market simulations in the first half of 2012. Equally important is to test the auction's potential vulnerability to manipulation through "table top" and other market simulation exercises, with oversight by market auction experts. Through such testing, ARB will be able to identify possible weaknesses in the design and undertake remedies prior to commercial and financial commitments being made in the first two auctions in 2012. (PGE4)

> **Response:** This comment falls outside the scope of the first 15-day change notice. Nevertheless, we recognize the importance of linkage with other regional, national and international programs. Subarticle 12 of this regulation provides possibilities for linkage, including procedures to evaluate external GHG emissions trading system. Furthermore, we will begin to test the market in 2012 and compliance requirements for covered entities start in 2013. This change ensures that all central elements of the program are developed and tested in 2012 before we move into the first year of compliance in 2013.

C. ALLOCATION OF ALLOWANCES

General Comments

Applicability and Methods

C-1. Comment: SCE appreciates the release of ARB's detailed allowance allocation proposal, which provides an equitable allocation method based on customer cost burden, energy efficiency accomplishment, and early action as measured by investments in renewable resources. (SCE3)

Response: Thank you for your support.

C-2. Comment: We encourage CARB to develop a straightforward LCFS process that can also be used for granting free GHG allowances to transportation hydrogen producers. (ICCT3)

Response: Your comment has been noted.

C-3. Comment: Uncapped establishments will not be subject to any form of direct GHG regulation and thus will not incur any costs in implementing reductions, buying and selling allowances, or in regulatory compliance, associated with AB 32. Regulated facilities are likely to face a competitive cost disadvantage to firms that provide a close substitute. The uncapped facilities, smaller emitters in this case, can increase their output and attendant GHG emissions, thus defeating the intent of AB 32 to reduce overall GHG emissions. Providing free allowances to large food processing emitters only partially mitigates this situation. In an industry where so much of the competitive in-state production will fall below the regulatory threshold, and so few of the capped facilities have large emissions (only a half dozen of the sector 3114 plants emit more than 50,000 tons), better public policy is to uncap the entire food processing sector and leave the emission reduction strategies to other means. For food processors, almost all emissions come through either natural gas or electricity use. The load serving entities for both natural gas and electricity will be under the Cap and Trade program by 2015. The energy utilities will have strong incentives to encourage their customers, including food processors, to reduce their emissions through utility-based programs and measures. Thus, the food processing sectors will be regulated through an alternative means, but in a less costly manner. CLFP recommends designating food processors (NAICS 3114) as an uncapped sector. (CALFP3)

Response: We do not agree the food processing sector should be uncapped in 2013. The cap-and-trade regulation is intended to regulate emissions from sources responsible for approximately 85 percent of California's GHG emissions, and in order to do this, large industrial sources and processes with annual GHG emissions at or above 25,000 $MTCO_2e$ must participate in the cap-and-trade program. The inclusion threshold balances broad coverage to provide the greatest possible reduction opportunities with minimizing administrative complexity in the beginning of the program. Including all sources at or above the threshold provides equity across all large stationary sources of emissions. In 2015, we include upstream coverage of fuel combustion at sources below 25,000 $MTCO_2e$. We will continue to monitor leakage of emissions to out-of-state or to in-state uncovered emitters that are below the threshold. The MRR will require reporting of emissions greater than 10,000 $MTCO_2e$, in order to monitor shifts in emissions from capped to uncapped producers within California.

Ten Percent Allowance Reduction

C-4. (multiple comments)
Comment: In Table 9-1, Industry Assistance Factors, WSPA believes that the 100 percent shown in the 2012-2014 columns for many sources does not "square" with ARB's proposal for a 10 percent haircut in initial allocations in Appendix B. (WSPA3)

Comment: It is important to keep in mind that for companies who have been designated as trade exposed, free allocation of allowances is a way to mitigate this trade exposure and to lessen the impact of a transition to a low carbon economy. CARB has concluded that free allocation of allowances, especially early in the program, is necessary and warranted to address trade exposure and to provide for a transition period. Therefore, when considering a method to distribute these free allowances, it is important that the method chosen and the design elements of that method do not run counter to the intentions of freely allocating allowances. Of most concern in this regard is the intention to reduce initial allocation by 10 percent (either through the benchmarking process or in other ways), which is suggested by staff to be necessary in order to fund various accounts or programs. This massive reduction in allocation would increase compliance obligations on affected regulated parties by 250 percent (from 4 percent to 14 percent) in the first compliance period—a period which was originally designed as providing a "soft start" and transition period for regulated entities. The justification for, and design of, a "soft start" to the Cap and Trade program was very carefully considered. The treatment of trade exposure and leakage avoidance was carefully and thoughtfully analyzed by staff with a primary result being full allocation in the first compliance period to sectors determined to be trade exposed. To the contrary, there seems to be little justification, rationale or analysis to support or explain consideration of a massive reduction in first compliance period allocation that would result in a 250 percent increase in the compliance obligation at the outset of the program. We strongly urge CARB to rescind any consideration of a reduced allowance allocation (or "haircut" as it has been referred to). The use of the first compliance period should continue to be viewed as a period that while it will deliver real, tangible emission reductions, allows regulated parties to transition to a low carbon economy. If any reduction in allocation is deemed necessary to fund various allowance accounts these allowances should come from sectors that have not been determined to be trade exposed, or that will benefit from the programs to which these allowances will be allocated (for instance, the electric utility sector should fund the VREC account, as voluntary renewables will reduce their compliance obligation). (BP2)

Comment: The proposed initial 10 percent "set aside" of allowances is unexpected and not recommended. A graduated start of the program, as presented in the Scoping Plan, would give California consumers and businesses time to adjust to the cost impacts of this regulation. This is particularly relevant given the now truncated first period of the program. (CONOCO2)

Comment: CARB proposes less than 100 percent allowance allocation for various industrial sectors in future compliance periods despite the fact that it has determined that these sectors, due to their energy intensity and trade exposure, qualify for 100 percent free allowance allocation. For those sectors determined to be energy intensive and/or trade exposed, CARB should be providing 100 percent free allowances, consistent with its own policy and in the interest of achieving the target reductions in the most cost-effective manner possible. (CALFP3, CMTA3)

> **Response:** We do not agree with the comments. As described in Appendix J of the Staff Report, product-based allocations are based on industrial product output and three other terms: (1) the product benchmark, (2) the assistance factor, (3) a cap adjustment factor. The 100 percent referred to by the commenters is the assistance factor term in this equation. The ten percent comment relates to the stringency of the benchmark term. We selected a benchmark stringency that reflects the emissions intensity of highly efficient, low-emitting facilities within each sector. The product-based benchmark for each activity is based on the largest of (1) 90 percent of the average emissions intensity for the sector, or (2) the emissions intensity of the best performer in California. More-efficient facilities, especially those with efficiencies better than the benchmark, will initially be receiving more allowances than they will need. Less-efficient facilities will need to purchase allowances to fulfill their compliance obligations. This is an incentive that we built in the system for industrial sectors to reward entities that took early action to reduce GHGs. This level of free allocation to each sector will be sufficient to minimize leakage and provide appropriate transition assistance.

Increase in Auctioning of Future Vintages

C-5. Comment: ARB's modified Cap and Trade draft Regulations allocate significant levels of permits to covered entities in the early years of the program, moving to an auction of greater volumes of allowances over time. We do notice on July 18, 2012, ARB now plans to transfer 10 percent of benchmark allowances for allocation from budget years 2015-2020 to the Auction Holding Account. This percentage is significantly increased from the originally proposed transfer of two percent and IETA has concerns about this "haircut" in allocated allowances starting in 2015. At this rate, industry will find it very difficult to adjust to the increased costs of auction, threatening competitiveness, jobs and consumer energy prices. Furthermore, allocating allowances helps to minimize leakage and prevent California industries from being put at a competitive disadvantage. Significant time and capital investment are needed to meet long-term emissions reductions goals and transition California to a lower-carbon economy. IETA recommends this ten percent haircut be returned to the original two percent. This will better help participants acclimate to the market and permit time for large capital investments to yield emissions reductions, keeping costs down, reducing trade exposure, and improving efficiency. (IETA3)

> **Response:** It appears that the commenter is referring to the increased amount of 2015-2020 allowances dedicated to an advanced auction. Auctioning of future vintage allowances will allow for development of a forward allowance price curve to inform long-term decision making by market participants. Selling future vintages also allows covered entities to begin to hedge against their future compliance obligations. The amount of advance auction was increased from 2 to 10 percent due to compliance entities' concerns about the ability to prepare for compliance obligations associated with upstream coverage of gasoline, diesel, propane, and natural gas.

Eligibility

C-6. Comment: Section 95890 requires that an entity obtain a positive or qualified positive verification statement to be eligible for direct allocation. WSPA believes this section needs to recognize that there are circumstances where an entity cannot get a qualified positive product data verification. This is a new procedure that could have complications. WSPA recommends that the Regulation be amended to allow an EO decision or a method for direct allocation in case a decision is pending on a qualified positive verification or in case of an adverse verification opinion. (WSPA3)

> **Response:** We do not believe there is a need to modify the regulation to allow an EO decision or a method as requested by the commenter for direct allowance allocations for entities that did not obtain a positive or qualified position product data verification. Appropriate flexibility is already included in the verification process.

Multi-Year Allocation

C-7. (multiple comments)
Comment: Under the current revision, CARB proposes to issue allowances on a one year forward basis and not multiple years. Choosing annual allocations over multi-year allowance allocations creates uncertainty for entities in terms of financial and capital planning purposes. It is not feasible for a facility to responsibly plan an expansion or retrofit for future years without knowing how it will obtain allowances to cover facility emissions in future years of the project. (CALCHAMBER3)

Comment: Per section 95910, CARB proposes to only issue allowances on a one year forward basis (not multiple years). This creates extraordinary and unnecessary uncertainty for financial and capital planning purposes. In addition, CARB is only auctioning off current year allowances and a limited amount of two year-ahead allowances, instead of multiple years of allowances. Limited allocations and auctions make it very difficult for new facilities and projects with traditional multi-year (e.g., 15-30) planning horizons. Some facilities, when faced with this uncertainty, can be expected to choose to site or expand facilities in states not subject to AB 32. As a result, CARB should follow the Acid Rain and RECLAIM program examples whereby sources are issued and allowed to trade multiple years of credits. (CANTORCO2E2, CIPA)

Comment: Without the benefit of multi-year allowance allocations, regulated entities will not be able to properly determine their growth potential and plan accordingly to select new sites or expand current facilities. A multi-year allocation approach allows regulated entities the time necessary for capital planning purposes. It is not very feasible for a facility to responsibly plan an expansion or retrofit that will take multiple years, if it must start the project without knowing how it will obtain allowances to cover facility emissions in future years of the project. Multi-year allocations will allow businesses to plan ahead. (CALFP3, CMTA3)

> **Response:** We do not believe that multi-year allocations are necessary. We believe that there is enough information in the regulation for a firm to forecast an expected allowance allocation through 2020. Because allocation is tied to production, if the firm can anticipate future levels of production they can calculate their allowance allocation for that period.

New Entrants

C-8. Comment: CARB should expand the “New Entrants” provision for the issuance of allowances to recognize significant expansions and modifications in operations. ConocoPhillips support CARB's provision to grant emissions to "New Entrants." ConocoPhillips strongly recommends that this provision be extended to facilities with "significant modifications" completed prior to 2011. The standards for a "significant modification" can be established with enough stringency to appropriately limit its use. For the refining sector, this could be defined as a project that required full CEQA review and exceeds certain production output thresholds. (CONOCO2, WSPA3)

> **Response:** We do not believe there is a need to expand the new entrants provision in Section 95891. Our preferred allocation approach is to use product-based benchmarks, which are used for the majority of facilities under the cap-and-trade program. In the case of product-based allocation, growth at an existing facility would increase the amount of product, thereby increasing the amount of free allocation. The energy-based allocation methodology, which contains the new entrant provision, is not the ideal method, and is only used for a small number of facilities whose products currently pose challenges to the use of the product-based allocation methodology. We believe that allowing for incumbent facilities in the energy-based allocation methodology to obtain more allowances for increased energy use may create perverse incentives to emit more greenhouse gas emissions. If possible, we would like to work with facilities

in the energy-based allocation methodology to develop product benchmarks and switch to the use of product-based allocation methodology for all facilities that are interested in expansion.

Facilities Dropping Below Threshold

C-9. Comment: In section 95812(e), if a facility leaves the program because its emissions drop below the threshold level it is not clear what happens to any allowances it has received free of charge. It also is not clear from the rule language whether leaving the program because of a decrease in emissions is optional or mandatory. We suggest a clarification of the consequences associated with a decrease in emissions and a provision similar to section 95813(f) for opt-out of opt-in entities, requiring surrender of allowances. (SCAQMD4)

Response: We disagree that additional clarification is needed. If a facility leaves the program, it retains all allowances it has received free of charge after accounting for the compliance obligation associated with all years for which it received free allocation. If a facility wishes to remain in the program after dropping below the threshold level of emissions, it may do so through the "opt-in" provisions of the regulation.

Effect on Industry of Increasing Electricity Allocation

C-10. Comment: WSPA is concerned that the allowance allocation system proposed by ARB would provide the electricity distribution utility sector "more than their share" of allowances, while other industries, including the petroleum industry, would be then given the "left-overs" on a pro-rata basis. Specifically, under the proposed allocation scheme outlined in Appendix A of the July 25, 2011 Proposed 15-day modifications, the electricity distribution utility sector will get 100 percent of customer cost burden plus 25 percent of their expected energy efficiency savings plus an amount related to renewable energy investments that they made in 2007 thru 2011. Approximately 1 percent of these allowances are allocated in recognition of projected energy efficiency, 0.5 percent of allowance from years 2013-2014 are allocated for recognition of renewable electricity emission reduction. Hence, the utilities' allocations would be in excess of their expected customer cost burden in 2013 range from 0.17 percent to 25.5 percent. Allowances should be allocated proportionally among all sectors. We think it critical that all sectors are treated equitably and that all industry including the petroleum industry be provided the same recognition for energy efficiency and early reduction as is given to the electricity distribution utility sector. (WSPA3)

Response: We do not agree that the allowances should be allocated proportionate to sector emissions. Our justification for allocation to electrical distribution utilities is fundamentally different than the justification for allocation to industrial sectors. The industrial allocation approach is designed to provide transition assistance and minimize emissions leakage. The electrical utility allocation is designed to protect electricity customers and provide these customers with rewards for utility investment in renewable energy and energy efficiency. Any allowance allocated to electrical distribution utilities must be used exclusively for the benefit of the retail ratepayers of each such electrical distribution utility, consistent with the goals of AB 32, and may not be used for the benefit of entities or persons other than such ratepayer. Industrial allocation is not subject to the same limitations. The differences between these two allocation categories are the reason that allocation to electrical utilities was not included in the pro ration of allowances to industrial producers.

C-11. Comment: Section 95870(d) has an increased allocation to electrical distribution utilities from 89 to 97.7 million metric tons CO_2e. This increase has the possibility of decreasing the allocations to industry assistance. It is not clear why this increase has occurred and what the potential effect it could have on industrial facilities. (CCGG2)

Response: We did not change the apportionment of allowances to the electricity sector. The Staff Report recommends that a set number of allowances be set aside each year for the electricity sector, starting with the 2012 allocation at 90 percent of 2008 electricity sector emissions, and declining linearly to 85 percent of that value by 2020. Using the mandatory reporting data, the 2008 emissions from electric generating facilities and imports were 98.9 million metric tons (MMT), so that 90 percent would be 89 MMT. Additionally, a portion of the electricity produced at facilities that identified themselves as cogeneration facilities was purchased by electricity distribution utilities. Using publicly filed data for 2008 and a heat rate based on the pending CPUC QF settlement, the estimated equivalent emissions from QF purchases is 9.67 MMT, so that 90 percent of this value is 8.7 MMT. The recommended 2012 allowance allocation to the electric sector is therefore the sum of 89 and 8.7, equal to 97.7 MMT. This approach was initially proposed in Appendix 1 to Board Resolution 10-42, entitled *Staff Proposal for 15-Day Changes to Address Electricity Sector Allowance Allocation*. This approach does not affect the amount of allowance allocation for industrial assistance.

C-12. (multiple comments)
Comment: Section 95870(e)(3) has an addition that in the event of a shortfall in available allowances, the industrial covered entities would only get a prorated amount of the available allowances after (a) through (d) are distributed. It is unclear why the industrial sector must bear the entire shortfall. A more equitable distribution of the shortfall would be to prorate the shortfall among sections (a) through (e). A spreadsheet that simulates the available allowances for sections (a) through (e) based on the latest reported emissions data would be helpful for regulated entities to better understand potential shortfalls. We ask that ARB make such a spreadsheet available to the affected sectors prior to the release of any further modifications. (CCGG2)

Comment: The proposed changes to section 95870(e)(3) now provides that if the total amount of allowances available, after all other sectors have received their allotted amounts, should be insufficient to meet the amount allotted for the industrial sector, then such remaining allowances shall be distributed on a prorated basis to the industrial sector. This is unfair, as the industrial sector is forced to absorb costs that should be spread equally across all sectors. It suggests a duplicitous intent by CARB and the utilities to conceal the true costs of the AB 32 scheme from California taxpayers and ratepayers by shifting the cost of insufficient allowances to industrial stakeholders. Fairness demands that all stakeholders should be exposed to the risk of insufficient allowances without favoritism or prejudice against any stakeholder for purposes of political expediency. Food processors, in particular, do not have the financial stamina to absorb own legitimate costs of allowances as against well-financed corporations through the auction; and the costs of CARB's attempt to shield utility ratepayers from "rate shock" associated with the implementation of AB 32. CLFP recommends that all sectors carry equal risk as to limited allowances. (CALFP3)

Comment: Section 95870(e)(3) would give the electrical distribution utilities the first share of allowances and then all other industries get a pro-rated share of what remains. WSPA opposes this electrical distribution utilities first scheme. WSPA recommends that ARB strike the word "industrial" in section 95870(e)(3). (WSPA3)

Comment: In the modified text, CARB reaffirmed its intention to prorate allowances only in the industrial sector in the event that the amount of allowances dedicated to specific uses exceeds the amount of allowances available in a given year. As a result, the industrial sector assumes the full risk that CARB mistakenly over-allocates allowances. This approach is counterproductive to the goals of the program given the concentration of leakage risk in the industrial sector. Accordingly, CSCME recommends that: (1) all entities receiving allowances be subject to the risk of proration and (2) the sequence of proration among these entities be prioritized in order to minimize the risk in sectors highly exposed to leakage. (CSCME4)

> **Response:** We do not agree with the comments. We never proposed to capture proration of electricity sector allowances under this provision. The amendments made to section 95870(e)(3) serve to clarify this initial intent. Our justification for allocation to electrical distribution utilities is fundamentally different than the justification for allocation to industrial sectors. The industrial allocation approach is designed to provide transition assistance and minimize emissions leakage. The electrical utility allocation is designed to protect electricity customers and provide these customers with rewards for utility investment in renewable energy and energy efficiency. Any allowance allocated to electrical distribution utilities must be used exclusively for the benefit of the retail ratepayers of each such electrical distribution utility, consistent with the goals of AB 32, and may not be used for the benefit of entities or persons other than such ratepayer. Industrial allocation is not subject to the same limitations. The differences between these two allocation categories are the reason that allocation to electrical utilities was not included in the proration of allowances to industrial producers.

Confidentiality

C-13. Comment: CARB noted at its July 15, 2011 workshop that it is "seeking comment on confidentiality of firm-level allocation." Firm-level allocation information for cement plants should be kept confidential. CARB recently published a graph with individual emissions intensities of the nine California cement plants. Although the individual plant names were not specified, CSCME respectfully notes that CARB should not have released this sensitive information with this level of particularity, because the data for the California cement industry include only nine plants. Confidentiality concerns are particularly relevant to the cement industry. Members of the industry treat virtually all company-specific and plant-specific data associated with energy costs and energy efficiency as confidential, because the cost of energy is a key driver of total production cost in this energy intensive industry. Under a cap-and-trade system, the cost of GHG emissions will assume similar importance. If firm-level allocation information were made public, competitors would be able to calculate several key measures via the allowance allocation formula. The public release of such information could, when coupled with other public sources, provide competitors with the data necessary to calculate output, GHG intensities, and regulatory costs for individual cement plants. This information would provide out-of-state producers with an asymmetrical competitive advantage that could exacerbate leakage in the California market. CARB should maintain the confidentiality of firm-level allocation information and should ensure that appropriate measures are in place to safeguard this sensitive information. (CSCME4)

> **Response:** Thank you for the comments. Since this is outside of the scope of the 15-day changes to the regulation, no response is necessary. We do note that in general because the production intensities we reported in graphs included adjustments for electricity sold and steam purchased, these graphs do not necessarily reveal the amount of production or energy used for production at any individual facility, as suggested by the commenter.

Allocation Not Equitable

C-14. (multiple comments)
Comment: While the 15-day language contains much more information than previous drafts regarding program allowance allocations and other critical program elements, it does not fully protect covered entities against potential equity, leakage or other material concerns. For example, that for some sources the staff have proposed a benchmarking methodology that will result in allocating at program commencement only approximately one half (l) of the allowances they will need to comply. Starting facilities significantly “in the hole” will create very significant leakage pressure and punish companies that have made material investments in California, among other reasons, to assure that their products meet highly-stringent California environmental standards. There is simply no basis for the program to provide some sources with full economic protection at the outset of the program yet to punish others. We urge the Board and staff to correct the existing disparities and inequities among sources, particularly those that would exist at

the outset of the program, so as to assure maximum fairness, to minimize the redistribution of wealth that inevitably will result from such disparities and to protect against leakage that could occur in the absence of such corrections. (CCC2)

Comment: While the Regulation proposes to freely allocate most allowances, primarily to mitigate emissions and economic leakage, we have concerns that this approach does not guarantee 100 percent allowance allocation fairly amongst industry sectors. While it's important to aid highly energy intensive trade exposed entities through the free allocation of allowances, requiring medium or low leakage prone industries to purchase allowances in the second and third compliance period will unnecessarily increase the cost of compliance for businesses, expanding these costs across to other California businesses and consumers. As long as California moves forward by itself in a Cap and Trade program, the risk of economic leakage will remain high. CARB should take every step possible to avoid this scenario. (CALCHAMBER3)

> **Response:** The allowance allocation distribution was developed through careful deliberation and analysis. We believe the approach provides the correct amount of leakage prevention and transition assistance to all Californian industries. As described in Appendix J of the Staff Report, many entities are expected to be able to raise product prices and pass on carbon costs to their customers. Providing excessive free allocation to firms with a high level of cost pass-through ability would have led to windfall profits. To address this concern, those with a lower leakage risk will receive fewer allowances due to the assistance factor term in the allocation equation, beginning in the second compliance period. In the benchmarking term of the equation, we set the benchmarks to reward efficient firms for their past action and to encourage less-efficient firms to reduce their carbon intensity.

Alternatives to Cap, Facility Shut-downs

C-15. (multiple comments)
Comment: Section 95891 of the Regulations indicate that facilities may not retain (nor gain) allowances if they cease operations. Depriving sources with the ability to gain revenue from the shutdown of emitting units will increase compliance costs (when streams of allowances from shutdown facilities are repatriated back to the state, we can presume that they will be sold through a state sponsored auction with a minimum clearing price ($10 in 2012) that will likely be above that which is offered on the secondary market) and encourage older/inefficient emitting units to stay on line. Knowing that it will forfeit its allowances and credits, a source operator will be inclined to keep the source operating as long as feasible. This will have the effect of discouraging equipment replacement (thereby keeping inefficient sources online) and keeping credits from the market (thereby reducing supply). As a means to mitigate costs and encourage companies to remove older and inefficient sources, CARB should allow for the creation of shutdown-derived offsets. Further, should CARB elect to issue multi-year allowance streams, companies should be allowed to retain, redeploy, or sell

allowances that are no longer needed by sources that are curtailed or shutdown. (CANTORCO2E2)

Comment: We recommend that ARB specify the fate of any allowances provided to a facility free of charge if the facility leaves the program because its emissions drop below the threshold for covered entities (section 95812). Our experience shows that considerable disagreement can arise about these stranded allowances if their disposition is not clearly set out in the regulations. (CAPCOA2)

> **Response:** We do not agree there is a need to add additional detail to specify the fate of any allowances after a facility exits the cap-and-trade program. Covered entities that are no longer subject to the cap-and-trade program due to reduced emissions are no longer eligible to receive free allowances. The free allocation is not a property right given by the program. Rather, free allocation is an incentive for efficient facilities to continue to operate in California. This incentive avoids emissions leakage and creates a smooth transition into the carbon pricing regime. The "true-up" terms explained in sections 95891(b) and (d) ensure allocation is matched with activities in the actual compliance years for facilities allocated to under these approaches. For facilities allocated to under section 95891(c), the regulation clearly states that entities that are no longer subject to the cap-and-trade program receive no future allocations. Any excess allowances not needed to match against emissions from the covered period are retained by the entity and may be sold.

Benchmarks

Miscellaneous

C-16. Comment: Provide that the anomaly years (short season start-ups, etc.) will be excluded in setting the benchmarks for the compliance period in which they occur. The years prior to a facility expansion should also be excluded (i.e., new boiler additions to existing facilities). New boilers should be treated as a new process and eligible for separate benchmarking and allowance allocations. (CALFP3)

> **Response:** We agree that anomalous data should be excluded when developing representative baseline allocations under the energy-based benchmarks. As to the addition of new boilers, our preferred approach for treatment of expansion at incumbent facilities is to address this issue using updating product-based allowance allocation.

C-17. Comment: There are 18 industry categories in Appendix B. However, five of those categories (not including Paper or Paperboard) are responsible for at least 91 percent of the 2008 GHG emissions from industrial facilities within the scope of the program. Thus, CARB is proposing to develop GHG efficiency benchmarks for 13 categories contributing 9 percent of the emissions. Aside from the general concerns with benchmarks and the development of benchmarks based on so few facilities, the administrative burden of developing, implementing, and enforcing benchmarks on facilities representing 9 percent of the emissions is simply a waste of both CARB's and the facilities' resources. (AFPA2)

> **Response:** We disagree. It is consistent with the leakage-minimization goal of AB 32 to include as many industrial sectors as possible under product-based benchmarks. Free allocation under the product-based approach will be updated annually to ensure that additional compensation is provided if production increases. Other methods of free allocation do not provide such a strong incentive to maintain or increase in-state production.

C-18. Comment: Air Products recommends that CARB clarify its intent regarding how new entrants subject to product-based benchmarks are treated by adding text comparable to section 95891(c)(3) under section 95891(b). (APC2)

> **Response:** We did not add additional text. New entrants covered under product-based allocation will receive allowances based on actual production levels once these data are available. The "true-up" term in the product-based allocation equation ensures that allocation for a given year is based on production for that year. The provisions in section 95853 offer flexibility in when a compliance obligation is assessed for new entrants. This section helps ensure that entities will have received free allocation prior to being required to participate in a full surrender of allowances.

Methods

C-20. Comment: AB 32 explicitly recognizes the importance of preventing negative consequences to certain industries caused by the implementation of a GHG reduction program, including both in relation to the direct emissions of carbon in their manufacturing processes and to the indirect emissions of carbon associated with the electricity they must purchase in order to manufacture their products. It places on the CARB the responsibility to "minimize leakage" (Health and Safety Code, sections 38562(a) and (b)). CARB has an obligation to ensure that all of the AB 32 goals, including the goal of minimizing leakage, are carried through in the implementation of the Cap and Trade program. CARB has generally recognized its responsibility with respect to "minimizing leakage". Resolution 10-42 and the accompanying appendices set forth in detail the considerations that the CARB included in developing its policy as well as more detail as to how CARB expects AB 32 implementation to proceed. CLECA agrees with these sentiments. Our concern with the proposed Regulations is that the CARB has not provided a mechanism to assure full protection from leakage that occurs as a result of significant increased costs to EITE industrial firms resulting from higher electric costs caused by implementation of its Cap and Trade scheme. It really is not clear how CARB intends to ensure full achievement of its obligation to minimize leakage through the electric utility allowance allocation process. Neither the Regulation nor Resolution 10-42 expressly direct the CPUC to ensure that the allowance allocation methodology fully protects EITE customers and thereby minimizes leakage. The risk we perceive is that once those free allowances are monetized and the revenues are placed under the control of the utilities and their regulator, the CPUC, the CARB's ability to specify and dictate uses for such funds may be compromised. While the CPUC's role is the regulation of electric utilities' costs and service, the CARB is the agency charged with the task of assuring that leakage is minimized. Clearly, the CARB has offered its "instructions" for disposition of such allowance auction proceeds. Unfortunately, the CARB's "instructions" regarding the disposition of allowance auction revenues are not sufficiently specific with respect to EITE customers and leakage and further, they may carry the weight of mere "suggestions" in the context of CPUC ratemaking. It is the CPUC, not the CARB, which has exclusive jurisdiction over investor-owned electric utilities with respect to ratemaking. If the CPUC determines that a substantial portion of the allowance auction proceeds should be spent on purposes other than "minimizing leakage", perhaps simply because it has not been specifically charged with that responsibility, the CARB could find that its task has been compromised. The initial proceedings at the CPUC in R.11-03-012, its rulemaking proceeding to assess how to treat both anticipated higher wholesale electric costs and allowance auction proceeds resulting from implementation of Cap and Trade, suggest that some parties will strongly urge the CPUC to direct the electric utilities to spend such allowance auction proceeds for purposes other than minimizing leakage, indeed for purposes other than benefiting ratepayers. Yes, the CARB, once informed of such actions by the CPUC and/or the utilities, might engage in the very cumbersome and time consuming process of modifying its Regulations to change the way in which it grants free allowances to utilities, but that approach would prove highly unsatisfactory given the amount of dollars at stake with respect to each year's allowances. CLECA sees two potential solutions. One is for the CARB to include such indirect electric costs in its determination of the benchmark for each EITE industry and to distribute allowances to such EITE entities sufficient to cover such costs, along with direct costs. This would, of course, require that allowances which were to be provided to the electric utilities to cover the usage of EITE customers are instead provided to the EITE pool. CLECA urges CARB to reconsider this aspect of its Regulations, specifically sections 95891 and 95892. Specifically, CARB should add a term to the Product Output-Based Allocation Calculation Methodology. Modify section 95891(b) as follows:

kWh purchased from the utility x utility emission factor/kWh.

CLECA believes that full protection of EITE customers requires that the allowances to be provided to them must include both direct and indirect costs and that the benchmarks can be set to accomplish that task. If indirect costs for EITE customers are covered in their allowances, such allowances would be deducted from those provided to the electric utilities and the utilities would be instructed not to give EITE customers any portion of the utilities allowance auction proceeds so as to avoid a double recovery. A second approach would be for the CARB to much more explicitly condition its grant of free allowances to electric utilities. CARB would make conditional its grant of free allowances to the utilities on their assuring that auction proceeds are used, in part, to fully cover the indirect costs of EITE customers. If the funds needed to cover EITE indirect costs were used for other purposes, the grant of allowances to the utilities would be adjusted downward and instead would be allocated by CARB directly to EITE customers. AB 32 places the responsibility to "minimize leakage" on the CARB and the CARB must adopt regulations which will effectively carry out that mandate. Modify section 95892(d)(3) as follows:

> <u>(D) Investor owned utilities shall use a portion of the auction proceeds to fully offset the greenhouse gas compliance costs reflected in the electricity rates charged to energy-intensive, trade-exposed customers consistent with the goal of AB 32 to limit emission leakage.</u> (CLECA)

> **Response:** We designed the regulation to minimize leakage as practicable while fulfilling the goals of GHG reduction mandated by AB 32. We believe it is premature to add provisions to the regulation to include indirect emissions associated with electricity at this time. This is because purchased power may not create an indirect carbon cost in all California utility service territories. It is our goal to see a carbon price properly embedded in all utility rates. If and when this occurs, the compensation for these indirect carbon costs could be incorporated into the product benchmarks (or reductions in these costs created in some other fashion) to help minimize leakage. We do not believe that a per kilowatt hour rebate is appropriate.

> As noted in the Staff Report, we are committed to monitoring how covered sectors, especially those that receive free allocation, address carbon costs once the program is in place. The goal of free allocation is not to “fully offset” greenhouse gas compliance costs; rather, the goal is to provide the correct incentive to maintain or increase production in California of highly greenhouse gas-efficient facilities, and thus minimize leakage and reduce greenhouse gas emissions.

> We are collecting product data from almost all sectors at risk for leakage. The data set from this collection will also serve as a key monitoring step in detecting leakage. We anticipate that the combination of using rigorous benchmark formulas and basing the free allocation on production data should ensure that free allocation appropriately minimizes leakage.

> We will revisit the issue of carbon costs embedded in purchased electricity once the CPUC proceeding addressing utility costs and revenue issues associated with greenhouse gas emissions concludes

> Per Board Resolution 10-42, we will continue to review information concerning the emissions intensity and trade exposure of different industries in California. We will recommend changes to the Board on leakage risk determinations, if needed, prior to the initial allocation of allowances for the first compliance period starting in 2013 for industrial sectors not identified in Table 8-1 of the cap-and-trade regulation. We will also do the same exercise prior to the initial allocation of allowances for the second compliance period starting in 2015, for industries

identified in Table 8-1 of the cap-and-trade regulation. Further, we will update the Board annually on the status of the cap-and-trade program, including, to the extent feasible, information on shifts in business activity that may result in emissions leakage and changes in market share for covered entities and sectors.

C-21. Comment: The CAF should be applied only to energy-related GHG emissions. CARB should exclude process emissions from the CAF for all industries. Unlike energy-related emissions, there is no practical technology for capturing or sequestering them. Purchasing allowances for process emissions will result in tremendous increases in the cost of these commodities, harming the industries' customers in essential industries. These increased costs will not encourage measures to reduce process emissions because the only way to reduce them is to curtail manufacturing. This will cost jobs, and send production overseas and to states other than California. Excluding all process emissions is a preferable approach because it is based, not on qualitative judgments as to how disproportionately large an industry's vulnerability is to leakage, but rather on what CARB staff intended to do, i.e. provide a separate rate of decline, and in effect applying the cap decline factor only to the energy use portion of the industries emissions. (NLA)

Response: We did not exclude all process emissions because we believe abatement options for these emissions could be developed in the future. We added additional flexibility in the cap adjustment factor for some sectors with process emissions that are greater than 50 percent of total emissions. Please refer to section 95891, Table 9-2.

C-22. Comment: Under section 95891(c), the Energy-based Allocation Calculation Methodology, facilities utilizing backpressure steam generation maybe be penalized. According to the formula for calculating GHG allowances, steam consumed at the industrial facility for any industrial process shall exclude any steam used to produce electricity. This promotes inefficiency since electricity produced in many industrial processing facilities is simply a byproduct of the process. A modern more efficient processing facility does not burn additional fuel to produce electricity, but captures energy that would otherwise be lost while supporting facility operations. In the backpressure turbine configuration, the turbine does not consume steam. Instead, it reduces the pressure and energy content of steam that is subsequently exhausted into the process header. With a backpressure turbine configuration, the energy produced by the turbine comes from reducing steam pressure, not from the generation of more steam. The efficiency gained from the utilization of these types of devices should be credited to the maximum free allocation, in addition to the 110 percent maximum limitation if a facility exceeds that limitation due to the inclusion of this device (as limited in section 95891(c)(2)). Staff has informed a CLFP member that a backpressure steam turbine generator has no negative impact in regards to section 95891(c). The variable "A_t," the amount directly allocated to an operator, will not be negatively adjusted and the facility will receive allocation based on the amount of fuel consumed ("$F_{consumed}$"); and that that no additional fuel or steam energy is consumed in the system as a whole from the backpressure steam. Therefore, CLFP requests that CARB modify section 95891 to reflect the above. (CALFP3)

> **Response:** We do not believe it is necessary to modify section 95891(c) significantly. We recognize that no additional energy is consumed in the system as a whole from the backpressure turbines the commenter describes. The fuel consumed by all units that produce electricity would be incorporated into the $F_{consumed}$ term. The backpressure turbine configuration generates no additional emissions and does not change the $F_{consumed}$ term. For clarification, in section 95891(c), the steam consumed term ($S_{consumed}$) was modified to explicitly exclude steam from any on-site cogeneration unit. If power produced from a backpressure turbine is sold, we expect the operator to recover some carbon cost in the price of the power sold, and would include this power in the e_{Sold} term.

C-23. Comment: We support requiring the industrial sector to base product benchmarks on best practices and allowing benchmarks to be dynamic over time, so that the rule provides additional incentives for using best practices to reduce emissions. (SIERRACLUBCA5)

> **Response:** We agree that benchmark stringency should reflect the emissions intensity of highly efficient, low-emitting facilities within each sector. We used a stringency based on the larger of 90 percent of the sector's average emissions intensity or best in California. We will review benchmark levels as part of required program reviews in the future.

C-24. Comment: CalChamber understands CARB's difficulty and challenge in establishing the industry benchmarks. The valid purpose of distribution benchmarks is to establish equitable bases for distribution of free allowances within industries, taking into account the complexity and existing energy efficiency of California facilities. Appropriate calculation of benchmarks is essential so that industry sectors know the anticipated cost of compliance, and can plan for future operations, projects, expansion, etc. We agree with a benchmarking system that rewards those facilities that are more energy efficient so long as the benchmarks are set correctly. (CALCHAMBER3)

> **Response:** No response is necessary.

C-25. Comment: In many of the cases presented in Table B of Appendix B, the proposed California emission intensity benchmarks are significantly higher than EU benchmarks, resulting in much higher emissions per ton of product. For example, the California emissions standard for Potash, Soda, and Borate Mineral Mining is 124 percent of the EU standard and for Recycled Boxboard Manufacturing is 200 percent of the EU standard. We are also concerned that the California benchmark for emissions intensity for cement plants is proposed at 0.786, while the EU standard (when adjusted) is only 0.716 (a significant 10 percent lower). We believe that ARB should be setting a world-class standard for GHG performance, and California industry should be able to meet or exceed EU standards. (EDLA)

Response: The European Union's Emissions Trading Scheme (EU ETS) benchmarks were developed based on selecting a value reflecting the average greenhouse gas performance of the top 10 percent of the installations in the EU that produced that product. This approach to stringency is slightly different from the 90 percent of average or best-in-California stringency that we used in our benchmarking. We believe our benchmark stringency rewards highly efficient facilities within California and, when combined with the other factors in the allocation equation, provides sufficient compensation to minimize leakage within each sector.

C-26. Comment: We recommend the identification of benchmark values (including identified impact levels where appropriate) for each identified metric that can act as a trigger for action by the agency. (EDF5)

Response: We do not agree that explicit triggers for action by the agency are needed in the regulation. Benchmarking is not used for setting the allowable level of emissions from any facility. The benchmark is one factor in the approach used to allocate free allowances. The goal of free allocation is to provide transition assistance to facilities in adjusting to the cost of compliance and to minimize leakage.

C-27. (multiple comments)
Comment: We recommend using these criteria to evaluate the GHG performance benchmarks: benchmarks should be transparent and based on publicly available information; the benchmark should be output (product) based, to maximize production in California; and the benchmark should be best in class to maximize carbon reductions and minimize associated criteria pollutants. (KUSTIN13)

Comment: CARB is proposing the use of a GHG performance benchmark to assess the relative carbon intensity of emitters. Polluters who meet or beat the benchmark will be given more allowances and so face lower costs relative to producers who are heavy emitters with higher carbon intensities. USC recommends the following criteria be used to evaluate alternative GHG performance benchmarks.

- The benchmarks should be transparent and based on publicly available information
- The benchmark should be output (product) based, to maximize production in California.
- The benchmark should be best in class to maximize carbon reductions and minimize associated criteria pollutants. (UCS7)

Response: Our product-based benchmarking methodology considered various elements, including the ones suggested by the commenter. To the extent feasible, we developed benchmarks based on appropriate product metrics, production-associated emissions, appropriate benchmark stringency, cost, and technical feasibility of compliance options. By necessity, we collected some facility information that was deemed confidential business information in setting the production benchmark within each sector. In a market-based program such as a cap-and-trade program, benchmarking is not used for setting the allowable level of emissions from any facility. The benchmark is just one factor in the approach used to allocate free allowances. The goal of free allocation is to provide transition assistance to facilities in adjusting to the cost of compliance and to minimize leakage.

C-28. Comment: We are very concerned over the mixed approach of developing GHG performance benchmarks based on 90 percent of average in some cases and best-in-class in other cases. We urge ARB to adopt a consistent best-in-class approach based on national and international data where possible. (KUSTIN13)

Response: To develop each benchmark, we began by analyzing the average emissions intensity of each sector and constructed benchmarks set at 90 percent of this average. "Best in class" benchmarks were developed, exceptionally, for any sector where the "90 percent of average" benchmark would be more stringent than the emissions intensity of any existing California facility in that sector.

C-29. (multiple comments)
Comment: CMTA supports direct allocation of emissions allowances without charge. The fundamental principle on which CARB has decided to conduct direct allowance distribution is the prevention of leakage by protecting industries that are energy intensive and trade exposed. The valid purpose of distribution benchmarks is to establish equitable bases for distribution of free allowances within industries, taking into account the complexity and existing energy efficiency of California industrial facilities. Benchmarks should be developed that are supported by the affected industries and serve to distribute allowances equitably among members of the industry. CARB should not use benchmarking methodology to serve unrelated goals and thus undercut the basic principle of free allocation of allowances to prevent leakage of emissions and economic activity of energy intensive and trade exposed industries. Benchmarks that penalize the superior energy efficiency of California industries relative to competitors in other states or that distort the distribution of allowances among industry members without regard to energy efficiency could result in significant allowance shortages for industry members relative to their in-state competitors. This will result in large allowance shortages for many facilities, with significant adverse impacts for California businesses and their workers. (CMTA3)

Comment: While CLFP supports the basic policy direction of free allocation of emissions allowances, the purpose of distribution benchmarks is to establish equitable bases for distribution of free allowances within industries. Benchmarks should be developed that are supported by the affected industries and serve to distribute allowances equitably among members of the targeted industry. CARB should not be using benchmarking and other distribution methods to undercut the free allocation of allowances to energy intensive and trade exposed industries. CARB should not adopt benchmarking methods which penalize the superior energy efficiency of California industries relative to competitors in other states, or methods which distort the distribution of allowances among industry members without regard to energy efficiency. Energy benchmarks should be set based upon a national standard. Setting industry-wide benchmarks, using only California facilities after nearly 30 plus years of energy efficiency efforts and expenditures by California industries, will only further exacerbate the trade exposure of California industrial facilities. Industry in California will be even more susceptible to competitors or startups in states choosing not to enact climate change regulations on their industrial base. Unfortunately, in CARB's most recent proposals on benchmarking, the basic principle of free allowance allocation is being subordinated to secondary concerns. This will likely result in large allowance shortages for many facilities and significant adverse impacts for California businesses and their workers. (CALFP3)

> **Response:** The commenters believe that setting industry-wide energy benchmarks using only California facilities will exacerbate the trade exposure of California industrial facilities. We believe that benchmark stringency should reflect the emissions intensity of highly efficient, low-emitting facilities within each sector. The allocation strategy will minimize leakage by incentivizing continued production and improved emissions efficiency from all facilities in California. We do not agree that this will result in adverse impacts for California businesses. We compared the benchmarks we developed against available national information and data from the European Union. In many cases the Californian benchmarks were more generous than what would have been established using the national or international data. We will review benchmark levels as part of required program review in the future and will consider national data as more information becomes available due to mandatory reporting of greenhouse gas emissions to the U.S. Environmental Protection Agency.

C-30. Comment: We urge the Board to give facilities, whether using an energy-based or product-based benchmark, the ability to select one of three options for the baseline period: (1) average emissions for 2008-10, (2) average emissions for any consecutive two-year period between 2008-10, or (3) any single year within that period. (MILLERCOORS)

> **Response:** We did not incorporate the proposed approach. We believe we provided sufficient flexibility to select representative data in both product and energy-based allocation methodologies.

Indirect Emissions

C-31. (multiple comments)
Comment: The GHG emissions that are incorporated into any product-based benchmarks for all sectors should include the emissions for the net power and heat used to produce the product. In order to ensure that there is even treatment of operators with cogeneration facilities compared to net purchasers of electricity and heat,

indirect emissions from imported power and heat should also be included in the benchmark calculation. (WSPA3)

Comment: WSPA strongly supports ARB's determination that because oil and natural gas production operations are global in nature, California facilities are highly trade-exposed. A natural extension of this determination is that any factor that could affect competitiveness of the in-state oil and gas production sector should receive explicit consideration and appropriate compensation under the Cap and Trade program. For California producers, electricity usage in oil production can vary widely, and for some, represents a significant portion of energy consumed. The proposed Regulation indicates that industrial customers (including oil and natural gas production) may receive energy efficiency programs or other indirect assistance, instead of the direct allocation of allowances or allowance value to address carbon cost impacts. For oil and natural gas production, energy efficiency programs, which can be useful for residential consumers or small commercial enterprises, do not provide value. Direct allowance distribution to the oil and gas production sector, more fairly addresses the impacts of higher energy costs that would otherwise disadvantage this highly trade-exposed sector. To allay concerns over the potential "double counting" of allowances already thought to be provided to the utility sector, the allowances for imported electricity can be deducted from the utility sector to prevent double counting. WSPA understood that ARB staff had agreed prior to the release of the proposed Regulation that direct allocations would be provided to make the oil and gas production sector "whole," but not until the CPUC acts on utility pass-through rules. The proposed Regulation should clearly address the matter of allowance distribution associated with electricity consumption for the oil and gas production sector; and how the proposed Regulation will mitigate the impacts of higher energy costs that would further disadvantage this highly trade-exposed sector. (WSPA3)

Comment: Refineries that purchase their energy compared to those who generate their own energy must be awarded comparable levels of free allowances or be eligible for CO_2 cost rebates. Some refineries are self-sufficient, generating all of their own power, steam and hydrogen while others rely partially or totally on third party and public utilities for their energy supply. For those refineries that are self-sufficient, the generation of these utilities is considered "inside their fence" and therefore eligible for inclusion in their free allocation calculation. This compares to a refinery that purchases their utilities that may not be eligible for free allocation since they are not considered "inside their fence." The market will require the refineries who purchase their energy to pay for the CO_2 costs at a 100 percent basis with no free allocations, thereby giving them a disadvantage by increasing their costs in an area they have no control over. This will have the effect of picking winners and losers. (TESORO2)

Comment: In order to minimize leakage, CARB should allocate allowances directly to industrial facilities with high exposure to leakage to account for indirect emissions. Failure to account for indirect emissions in the construction of the cement industry benchmark increases the risk of leakage. CARB's revised Section 95892(a) might appear to address this concern by requiring electrical distribution utilities to use allocated allowances "exclusively for the benefit of retail ratepayers." This provision for indirect emissions, however, is inadequate, because no guidance is provided as to how to allocate allowances among ratepayers. Providing general guidance to use allocated allowances "for the benefit of retail ratepayers" is insufficient action to ensure CARB is fulfilling its mandate under AB 32 to minimize leakage. For industries with high exposure to leakage, CARB should allocate allowances directly to compensate for indirect emissions. This would be consistent with the approach that was proposed at the federal level in the Waxman-Markey bill and would ensure that CARB fulfills its statutory mandate to minimize leakage. (CSCME4)

> **Response:** We recognize the importance of indirect carbon costs. We include adjustments for purchased heat and for heat and power sold in both the product-based and energy-based benchmarking. We believe it is premature to add an adjustment for power purchased at this time. This is because purchased power may not create an indirect carbon cost in all cases. It is our goal to see a carbon price properly embedded in all purchased power, including utility rates. If and when this occurs, the compensation for these indirect carbon costs could be incorporated into the product benchmarks (or reductions in these costs created in some other fashion) as necessary to help minimize leakage. We will revisit this issue once the CPUC proceeding addressing utility costs and revenue issues associated with greenhouse gas emissions concludes.

Stringency

C-32. (multiple comments)
Comment: The petroleum industry is both an energy intensive and trade exposed industry and therefore should be eligible for 100 percent allowance assistance per section 95870. This fact makes it clear that benchmarking should be per the adjusted EII methodology. However, in Appendix B, ARB proposes a 90 percent benchmark stringency, in essence a 10 percent haircut from the Cap and Trade program. ARB has justified this 10 percent haircut in a number of ways, including the need to fund reserve allowances so as to fund program needs. WSPA does not agree with the stringency concepts for the 10 percent haircut, but understands the concept of holding back some allowance to fund various accounts when the Cap and Trade program is initiated. We are concerned however, that the initial 10 percent reduction in initial allocations implicit in ARB's proposal is excessive, unsubstantiated by need, and in fact may cause irreparable harm at the start of the program when it may be most vulnerable. The 10 percent haircut is excessive when one considers the provisions within section 95870 (Disposition of Allowance). We note that the proposed section specifies that 1 percent of the first compliance period allowance budget is to be set aside for the Reserve and 0.5 percent of the allowances from those same years are to be set aside for the Voluntary Renewable Electricity Reserve Account. Hence, it seems clear that 98.5 percent of total First Compliance Period allowances should be available for initial distribution to industrial facilities including the refining sector. This amount contrasts with the 90 percent remaining at the start of the program and does not even take into consideration the two percent reduction that is inherent in the program for 2013 and

2014. In short, if the 10 percent reduction in the initial year is realized, the first compliance period (2013 and 2014) will see a total reduction of 14 percent reduction in emissions— well in excess of program requirements and comprising nearly the entirety of the original AB 32 target. WSPA opposes this 10 percent reduction in initial allocations because its use will penalize all operations, even the high performing facilities. Any significant reduction in initial allocations will undermine one of ARB's key objectives in allowance allocation, which is transition assistance and minimizing leakage. (WSPA3)

Comment: ARB staff asserts that 10 percent reduction in all allocations is needed to fund all reserves. However, 10 percent reduction across the board appears to over-fund the initial reserve requirements while making compliance more difficult in the early (transition) years. In order to determine the most appropriate reduction in the initial allocation, ARB should calculate the actual amount of reserves required to be funded in the first two years and then determine what percent reduction is needed to fund that requirement. (WSPA3)

Comment: The free allowance allocation methodology applies an arbitrary factor of 0.9 to the benchmark, resulting in a 10 percent reduction in allowances to the sector. This reduction is required from the start of the program and is in addition to the successive annual cap reductions required under AB 32. Not only is this reduction excessively difficult when compounded with the cap reduction but it also undermines the emissions leakage protection that CARB intended to provide. (EXXONMOBIL)

Comment: The Assistance Factor of 100 percent for the first compliance period was intended by CARB to avoid leakage as trade-exposed industries transitioned into the program. Refining is a highly trade-exposed industry and California refiners stand to lose competitiveness if subject to excessive regulation that refiners outside of the State are not. A reduction as significant as 10 percent has the potential to make California refining uncompetitive, leading to leakage of investment, production, jobs and emissions. (EXXONMOBIL)

Comment: CARB should adopt a cement benchmark that is based on the industry's average GHG intensity. We believe this approach is more equitable and more consistent with the objective of minimizing leakage to the extent feasible. Use of a "best in class" emissions intensity benchmark would impose immediate compliance costs on all California cement plants that would not be borne by imports. (CSCME4)

Comment: The proposed Regulation includes provisions for granting free allowances to industrial facilities. It also establishes the benchmark at a level of 90 percent of industry average for the refining sector and most other industries. Setting the benchmark at this level will create an immediate shortage of free allowances leading to a level of stringency in the program that will create immediate impacts, dilute the impact of the assistance factor, and be redundant with the cap reduction factor. The only clearly stated need for allowance withholdings during the first compliance period are 1 percent for the price containment reserve and 0.5 percent for renewable electricity emission reductions. There is no justifiable reduction in free allowances beyond 1.5 percent in the first compliance period. Because the cap reduction factor already provides for a 2 percent yearly reduction in free allowances, the 90 percent initial reduction is overreaching, beyond the needs of the program, and will cause unintended consequences like market leakage. (TESORO2)

Comment: Design the program elements to ensure a smooth transition. CCEEB recognizes that ARB has proposed several program elements designed to create a smooth transition to a market, such as the transition assistance. However, design elements, such as the benchmarking methodology and the stringency of the benchmark can place some facilities in a position that will require reductions or compliance obligations that are five to ten times more than the average cap reduction for industry, beginning in the first year. The benchmarking methodology and stringency should be carefully considered to provide a smooth transition period for entities. (CCEEB3)

Comment: The purpose of distribution benchmarks is to establish equitable bases for distribution of free allowances within industries, taking into account the higher complexity and existing energy efficiency of California industrial facilities. CARB should NOT be using benchmarking methods to arbitrarily withhold up to 10 percent of the allowances that trade exposed and energy intensive industries need in order to minimize costs and leakage. This is inequitable, does not minimize costs, and does not minimize leakage. CARB should discontinue this proposal, and should not arbitrarily withhold allowances that it has already determined these industries need. CARB should continue to work with trade exposed and energy intensive industries to develop benchmarking methods that are supported by the impacted sectors. (AB32IG2)

Comment: A stringent benchmark reduces industry assistance and leads to leakage. The proposal arbitrarily sets the benchmark for industry sectors at 90 percent of the industry average. This results in a reduction of industry assistance to 90 percent for the first compliance period from 100 percent as proposed in the December 2010 rule. ARB should provide 100 percent free allowances to industry to prevent leakage of jobs and emissions out of the state, consistent with the December 16, 2010 cap and trade rule. The proposal reduces industry assistance by setting the benchmarks at 90 percent of the industry average which results in industry having to purchase the remaining allowances at auction**.** (CHEVRON3)

Comment: Significant reductions in initial allocations will lead to leakage and adverse economic impacts to the State. The mandated haircut is excessive because the most recent emissions projection reflecting the economic downturn reveals that such reductions are unnecessary given the economic downturn. ARB's most recent emission projections show that the "Business as Usual" (BAU) target has been dramatically reduced leading, directly, to a reduction in the required AB 32 emission reductions. Finally, we note that the "haircut" should not be thought of as merely an impact on some arbitrary benchmark. Rather, more precisely, it is an impact on industry and on all market participants. ARB should fund the initial reserves without the large haircut and distribute the remaining allowances equitably in order to facilitate a smooth start to the program. We stress that excessive removal of allowances such as proposed, will make allowances artificially scarce and could dramatically impact market participants without a corresponding reduction in GHG emissions. ARB should distribute all allocations at an amount equal to 100 percent less the initial reserve funding requirements. While any reduction from 100 percent allowances will lead to leakage, if it is impossible for ARB to follow through on their commitment for full industry assistance, then the initial “haircut” should be no greater than 1 percent given all anticipated funding and program requirements. (WSPA3)

Response: We do not agree. We believe that benchmark stringency should reflect the emissions intensity of highly efficient, low-emitting facilities within each sector. The allocation strategy will minimize leakage by incentivizing continued production and improved emissions efficiency from all facilities in California. We do not agree that this will result in adverse impacts for California businesses.

We arrived at the 90 percent of average product-based emissions efficiency benchmark after careful analysis of data and approaches used in other successful cap-and-trade programs. We are balancing the need for providing adequate transition assistance and minimization of leakage while meeting the emission reduction goals of AB 32. To develop each benchmark, we began by analyzing the average emissions intensity of each sector and constructed benchmarks set at 90 percent of this average. "Best in class" benchmarks were developed, exceptionally, for any sector where the "90 percent of average" benchmark would be more stringent than the emissions intensity of any existing California facility in that sector.

Within each sector, the most efficient facilities with efficiencies better than the benchmark will be receiving more allowances than they will need, and can sell their excess allowances. Less-efficient facilities will need to purchase allowances to fulfill their compliance obligations. Beyond the initial allocation period, the level of free allowances will decline through the use of a cap declining factor and an assistance factor. Because allowances can be traded, the program provides incentives for those with the most cost-effective reduction opportunities to reduce emissions quickly. This is an incentive we built in the system for industrial sectors to choose innovation for reducing GHG.

True-Up

C-33. Comment: CSCME commends CARB staff for its proposed modifications to the output term of the allowance allocation system, including the use of output data from the most recent year available and the inclusion of a "true-up factor" in the allocation formula. (CSCME4)

Response: No response is necessary.

C-34. Comment: PPG has reviewed the proposed product output-based calculation in Section 95891(b) and the related commentary in the equation notes and the section of the July 25, 2011 Notice of Public Availability regarding section 95891. In the equation notes, the purpose of the true-up factor is explained as a factor used to "adjust for any output not properly accounted for in prior years' allocations." In the Notice of Public Availability, the true-up factor is explained as an addition to the equation "to ensure that the amount of allocation received for a given year is corrected to actual production for that year." However, the true-up factor, as proposed, does not have anything to do with correcting a previous over- or under-allocation due to improper, erroneous or corrected production numbers for a previous year. Despite the stated purpose of the true-up portion of the equation, it appears that its actual function is a modified version of the previously proposed production-averaging concept, in which the three-year averaging period is reduced to two years (i.e., t-4 and t-2). If the intent, as stated in the Notice, is "to change the timing of output data to respond to stakeholder concerns about prolonged exposure to recessionary output levels," PPG does not believe that the addition of the proposed true-up factor to the product output-based equation achieves the goal. In fact, it preserves the averaging function and the "prolonged exposure to recessionary output levels" because, for any period where production is growing year-over-year, the true-up portion of the equation (in which t-2 production is subtracted from t-4 production) results in a significant reduction in allocated allowances for the current budget year due to the lower production in the earlier year (i.e., t-4). Conversely, when production has decreased year-over-year, it appears that the number of allowances allocated will increase for the current budget year due to higher production in the earlier year. PPG understands the need to ensure that product output-based allocations are based on accurate production numbers. Thus, the application of the true-up portion of the equation to reported changes in or corrections to previously reported annual production numbers would be appropriate. But an across-the-board application of the true-up portion of the equation to all sources every year will only serve to "prolong exposure to recessionary output levels," which the factor is ostensibly intended to avoid. PPG recommends that the true-up portion of the equation be deleted and presented separately as an equation to be applied in the allocation process only in the event that a covered facility has submitted a correction to a prior year's reported production. Under that approach, any previous over-allocation or under-allocation of allowances to a facility in a prior year could be corrected, without any impact on other facilities in the cap-and-trade program. (PPG1)

> **Response:** We disagree, and believe that the commenter has misinterpreted the equation. The true-up term will allocate additional allowances if actual production in a given year was larger than estimated initially. We modified section 95891(b) to clarify our approach. $O_{a,t}$ is replaced by $O_{a,initial}$, which will be calculated by the Executive Officer as the output in year t-2 as reported to ARB. $O_{a,trueup}$ adjusts for any output in year t not properly accounted for in prior allocations.

C-35. Comment: CSCME commends CARB's proposed modifications to the allowance allocation system in order to ensure alignment between actual and intended allowance allocations. CSCME believes that these proposed modifications represent a significant step in the right direction. We recommend one additional adjustment to ensure the adoption of a "pure" true-up method. Specifically, CSCME recommends that, rather than applying the true-up factor to future allocations, CARB should apply it to existing compliance obligations. The merits of this approach are relatively straightforward. In order to accurately assess compliance obligations, CARB must have verified MRR data on both a facility's emissions and output during the compliance year in question—therefore, it has all the data it needs to perform a "pure" true-up. Furthermore, CARB only needs to remove the true-up factor from the allowance allocation formula and apply it as an offsetting term in the calculation of a facility's outstanding emissions obligations. (CSCME4)

> **Response:** We believe our second 15-day change to the regulation for section 95891(b) is sufficient. $O_{a,t}$ is replace by $O_{a,initial}$, and $O_{a,initial}$ will be calculated by the Executive Officer as the output in year t-2 as reported to ARB. Further, the inclusion of the $O_{a,trueup}$, which adjusts for any output in year t not properly accounted for in prior allocations, should adequately address the concerns raised. We prefer to keep the calculation of the allowance allocation separate from the calculation of the compliance obligation.

C-36. Comment: The true-up calculation in section 95891(b) should be clarified to ensure that entities are issued sufficient allowances to account for production increases over time. $O_{a, trueup}$ in the trueup calculation is defined as “the difference between the output reported in data year ‘t-4’ and the output reported in data year ‘t-2.’” A literal reading of this could require calculation of output in t-4 minus output in t-2. But the true-up should really be t-2 minus t-4; otherwise, if there was higher output in t-2, the entity would not have had enough allowances allocated based on t-4, so the trueup should add allowances. We respectfully request that CARB clarify the trueup calculation and provide for additional comment on clarified language. (JM)

> **Response:** We agree, and modified section 95891(b) to clarify our approach. $O_{a,t}$ is replaced by $O_{a,initial}$, which will be calculated by the Executive Officer as the output in year t-2 as reported to ARB. $O_{a,trueup}$ adjusts for any output in year t not properly accounted for in prior allocations (t-2 minus t-4). The true-up adds allowances if the actual output in a given year is higher than initially estimated. Conversely, allowances are withheld if initial output estimates were too high relative to actual values.

C-37. Comment: The current methodology as described is not adequate in providing sufficient allowances for those sources that have invested in clean technology, energy efficiency and industrial growth in the state of California. This is particularly important in light of the state’s precarious economic condition, and ARB’s stated sensitivity to the financial impact of compliance, especially in the initial years of the program. The insufficiency is related to the manner in which the compliance obligation is set and the allowances are allocated. Different production years are used to determine the compliance obligation and the allowance allocation. The Regulations base an industrial source's compliance obligation on their current year's level of emissions reported to the ARB under the Mandatory Reporting Program. Emissions are based on the source's current level of production in that same year. For example, the compliance obligation in the year 2015 is based on that source's emissions and level of production in the year 2015. However, the allowances allocated to that source for the year 2015 would be based on its production level in the year 2013. A facility that may have experienced production growth between 2013 and 2015 could find itself with insufficient allowances because different years are used as baselines in determining emissions and allowances. ARB intends to provide allowances prior to the beginning of the compliance year. Therefore, allowances for 2015 would be awarded at the end of 2014. As the 2015 production is not known until the end of the year, ARB has introduced a "true-up" calculation formula in an attempt to provide allowances to make up the difference between the estimated level of production and the actual level of production for 2015. Unfortunately, the true-up calculation also uses production levels from previous years in estimating the true-up amount. As an example, for the 2015 true-up, the difference in production between the years 2011 and 2013 is used in estimating the true-up. If there was a decline in production between 2011 and 2013, the true-up could even have a negative value, regardless of what actually occurs in 2015. A more equitable means of allocating allowances would be, as much as practicable, to use the level of production from the same year that is used in reporting emissions in the equation at section 95891(b). An additional true-up during each production year, perhaps in the late third quarter of the year, might be explored as a solution. Such an approach would certainly reduce the uncertainty for companies and would represent a more accurate and timely coverage of their exposure for allowance needs. This issue of proper true-up of allowance allocation is especially important in the weak economy which we face today. If struggling companies in the current recession are forced to buy allowances that they have counted on to be "free," it could push many of them over the edge. Under the currently proposed methodology, the need to buy allowances is likely to happen in many cases as companies' production levels gradually increase coming out of the recession. An improper true-up mechanism is especially damaging for companies that have "taken the plunge" to invest in increased production capacity in recent years. CSI is one example. CSI spent more than $70 million during the recession to invest in a new, cleaner reheat furnace, representing state-of-the-art emissions control technology for its production of hot-rolled steel sheet. The new furnace reduces greenhouse gas emissions per ton of steel produced, and also allows about 50 percent greater production capacity, which helped justify this major expenditure. Now, as CSI seeks to obtain the expected payback on this investment, it will be seeking to grow its production and sales beyond the levels that existed prior to the recession. In a scenario of annual growth for several years, a company such as CSI will be constantly coming up "short" on allowances and having to go to market to buy them—even though the new production capacity produces fewer emissions per unit of production. This result is not fair or reasonable and is both damaging to the economy and punishing to companies willing to invest in growth in California. (CSI)

Response: Our approach is fair and reasonable, and it minimizes leakage. It provides various incentives and safeguards to transition industry to a low-carbon economy. The amount of free allowances distributed under our allocation approach will vary with economic conditions. This means that, in an economic downturn, there will likely be fewer allowances distributed for free due to a decrease in production or output. When economic activity is robust and output increases, a greater number of allowances will be freely allocated. The triennial compliance obligation (except two years for period one) per compliance period will provide facilities with flexibility. Expansion at incumbent facilities is adequately addressed—as facilities produce more product, they receive additional allocation. The benchmark-based allocation system also recognizes and encourages early action. Benchmarks are chosen to reward facilities who have historically chosen to employ low-GHG fuels and enhance their emission efficiencies of their production process. Facility projects that reduce CO_2 emissions would save money in the form of either a reduced need to purchase allowances at auction or in the form of allowances given for free under our cap-and-trade program.

We modified section 95891(b) to clarify our true-up approach. $O_{a,t}$ is replaced by $O_{a,initial}$, which will be calculated by the Executive Officer as the output in year t-2 as reported to ARB. $O_{a,trueup}$ adjusts for any output in year t not properly accounted for in prior allocations.

C-38. Comment: PNA would like clarification from CARB that the first trueup factor in section 95891(b) would be applied in 2015 to reconcile the production in years 2011 and 2013. PNA also notes that the trueup factor will only account for changes in emissions that are directly linked to production and not those emissions that are needed to keep the glass furnace hot during hot holds or start-ups and shut-downs associated with cold repairs.

PNA seeks confirmation from CARB that the furnace would not be considered shut down during a cold repair or a hot hold as the term is defined in the cap and trade rules despite the fact that no glass is being produced, and that neither a cold repair nor a hot hold necessarily represent an intention to cease production, but instead are considered to be routine maintenance and repair events. As the rule is currently drafted, it seems that PNA would have a compliance obligation for the emissions during these idling periods, but would not receive any allowances for this time because the product output-based allocation methodology includes only a single year of production and there would be no production during hot hold periods and periods of cool-down or heat-up.

PNA recommends that a factor be added to the existing product output-based "trueup" factor to account for the actual emissions from the fuel combustion during the time period in which the furnace is idled but not shut down, and that such a factor be based on the fuel benchmark used for the fuel portion of the thermal energy-based allocation methodology multiplied by the actual amount of fuel burned during the hot hold period. (PNA)

Response: We modified section 95891(b) to clarify our approach. $O_{a,t}$ is replaced by $O_{a,initial}$, which will be calculated by the Executive Officer as the output in year t-2 as reported to ARB. $O_{a,trueup}$ adjusts for any output in year t not properly accounted for in prior allocations. The glass benchmarks were set after consideration of the routine maintenance and repair events the commenter outlines. We did not add a factor based on the period where the furnace is idled but not shut down.

Cement

C-39. Comment: We strongly support the cement benchmark that is based on best-in-class for clinker production with mineral additives. This will incentivize the use of supplementary cementitious materials added directly to cement (in addition to the additives that can be used in concrete) as well as process and fuel efficiency improvements to the kilns. (KUSTIN13)

Response: No response is necessary.

C-40. Comment: We fail to find a suitable explanation for the greatly diminished emission reduction obligations for the cement sector compared to all other sectors, as reflected in the Cap Adjustment Factors in Table 9-2 of the regulation (p. A-120). (KUSTIN13)

Response: This comment falls outside the scope of the first 15-day changes to the regulation. However, in the second 15-day changes to the regulation, section 95891, Table 9-2 was modified to define “sectors and activities associated with process emissions greater than 50 percent.” In the original proposed text in the 45-day notice, we identified only cement manufacturing as an activity associated with significant level of process emissions for which minimal cost-effective abatement opportunities are currently available. Stakeholders in other sectors whose activities also release process emissions raised concerns in comments. After careful consideration, we determined that some additional sectors with activities that are associated with process emissions greater than 50 percent are eligible for a lower cap adjustment factor, taking into consideration the potential impact from the emissions that currently have few cost-effective abatement opportunities. A cap adjustment factor for all industries ensures equitable incentives to all producers to minimize leakage as a result of the cap-and-trade program.

C-41. Comment: In the industrial sector, the free allocations are excessive and should be reduced. Free allocations based on industry-specific benchmarks encourage some moderate efficiency, but may disadvantage innovators (for example, Calera, Inc., a new company that produces carbon negative cement products). How many free allowances would a start-up like Calera get in relation to an incumbent cement factory? Free allocations may prevent “leakage” of the old technology by shielding business-as-usual from the carbon price. (CPC6)

Response: We do not agree that the proposed free allocations are excessive and should be reduced. We studied the strengths and weaknesses of all existing cap-and-trade programs, including the European Emissions Trading System, and learned from these systems in developing our program to avoid over- or under-allocating allowances. We determined that a soft start, under the current economic conditions, dictates greater reliance on free allocation of allowances in the early years of the program. We view this free allocation as critical to avoid adding an immediate cost to covered industries that could inhibit their ability to invest in emissions reductions. As the program progresses, we propose a transition to a greater reliance on auctions for allowance distribution while still minimizing leakage where risk exists. In addition, we are committed to monitoring the implementation of our program and making adjustments as necessary.

The commenter’s statement that free allocations based on industry-specific benchmarks encourage some moderate efficiency, but may disadvantage innovators, is not true. Any facility that produces cement may opt-in to the program regardless of emissions levels. Innovators that choose to opt-in to the program and can produce cement at an emission intensity lower than the benchmark would benefit due to the able to sell allowances. In addition, even if the innovative firm chooses not to opt-in and sell allowance, they enjoy a competitive advantage relative to the dirty firms above the benchmark that face carbon costs as a result of the program.

C-42. Comment: CARB's proposed benchmark for the cement industry does not reflect early actions taken by the industry to reduce its GHG emissions in anticipation of AB 32 implementation. CARB data suggest that the cement industry has significantly increased its use of biogenic materials from 2006 (i.e., the year in which AB 32 was adopted) to 2009 (i.e., the year used to establish the benchmark). CARB should modify the cement benchmark to account for these voluntary actions by California cement producers between 2006 and 2009. (CSCME4)

Response: We believe product benchmarks should be set with consideration of how the compliance obligation will be determined. Since biogenic materials, if they meet the provisions of the regulation, do not count toward a facility’s compliance obligation, we do not believe it is appropriate to include these emissions when setting the product benchmark. We also reviewed the amount of biogenic materials used by cement sector facilities for the year 2006, 2008, and 2009, and did not find a sector-wide increase. Therefore, we believe that the benchmark does not have to be changed to take into account the change in biogenic materials consumption by cement sector.

Food Manufacturing

C-43. (multiple comments)
Comment: Under the current proposal, emission allowances for breweries would be benchmarked using an energy-based methodology that assumes boiler efficiencies of 85 percent for the years 2008-10 and ratchets down emission levels in three-year increments through 2020. Among the inherent flaws of energy-based benchmarking approach for beer production are that it fails to reward producers that took early actions to reduce emission levels in the three baseline years, gives no recognition to how efficiently a brewer uses its fuel inputs in the production process, encourages large brewers to import more beer from their out-of-state plants, and effectively caps beer production at the major California breweries at 2008-10 levels. Because of these deficiencies, MillerCoors urges the Board to place breweries within a separate industrial classification and apply a product-based benchmark methodology to allocate allowances. A product-based benchmark would cap emissions from breweries on a per-unit of production basis, such as annual CO_2e per barrel of production. Product-based benchmarking is particularly appropriate for breweries because beer is a homogenous product with each unit of production having similar energy inputs. Differences in emissions per unit of production would be reflected almost entirely by the relative energy efficiency of each brewer's production process. More importantly, the product-based approach allows a brewer to expand beer production within the state without having to purchase additional allowance since efficiencies of scale are likely to result in lower emissions from each incremental barrel of production, even though total energy use would increase. Finally, product-based benchmarking creates the correct incentives for brewers by encouraging investment in the best available technology to get the most production from the least amount of energy inputs. (MILLERCOORS)

Comments: Because only three breweries within the state are subject to the proposed Regulation, Miller Coors' support for product-based benchmarking is conditioned on using average emission intensity data from comparable brewing facilities operating in other states. This approach recognizes the relatively higher production efficiencies already achieved by California-based breweries because of the State's high energy costs. Using out-of-state breweries in the benchmarking calculation also addresses what we believe is an understatement of the leakage risk for beer production due to the potential for large brewers to bulk ship beer in refrigerated rail tank cars for local bottling. (MILLERCOORS)

Comment: While we think that product-based benchmarking would be advantageous for all California breweries, we recognize that may not be the case. Consequently, MillerCoors would like the option of benchmarking emissions from Irwindale, where MIllerCoors made significant investments and reduced GHGs by 16 percent below 2008 levels, against the average per unit of production emissions at other comparable MillerCoors breweries in the United States. (MILLERCOORS)

> **Response:** We agree, and will continue working with all industry falling under the energy-based allocation methodology that would like to develop product-based benchmarks.

C-44. Comment: Ag Council agrees with ARB staff assessments in the December report regarding domestic competition as being problematic as it relates to the food and agricultural industry. A different approach should be taken for food processing in determining compliance costs and/or emissions intensity. The emissions intensity variable in the product-based allocation calculation should be replaced with another variable that truly represents the cost of compliance for the food industry. Staff should take more time to work with the food processing industry to determine an appropriate factor for this variable. (ACC4)

> **Response:** The food processing industry is not being allocated allowances based on the product-based allocation methodology. Instead, food processors are allocated using the energy-based allocation methodology. Pertaining to energy intensity and trade exposure, Board Resolution 11-32 directs the Executive Officer to initiate a study to analyze the ability of the agricultural industry, including food processors, to pass on regulatory costs to consumers, given domestic and international competition and continually fluctuating global markets. The Executive Officer is directed to identify and propose regulatory amendments, as appropriate, as a result of this analysis.

Gypsum

C-45. Comment: The Gypsum Association and its members request that ARB change the relevant references in Table 9-1 of section 95891 and Table B in Appendix B to correctly identify that the benchmark unit for plasterboard production is based on the mass quantity of stucco used to produce salable plasterboard and not the quantity of plasterboard produced. In Table 9-1, Product Based Emissions Efficiency Benchmarks, units should be changed for the benchmark in the "Plaster Board Manufacturing" activity from "Allowance/Short Ton of Plaster Board" to "Allowance/Short Ton of Stucco Used to Produce Saleable Plasterboard." In Table B, Comparison of California and EU ETS Product Benchmarks, units should be changed for all benchmarks (CA Imperial Units, CA SI Units, and EU ETS) in the "Plaster Board Manufacturing" activity from "…Ton of Plaster Board" to "…Ton of Stucco Used to Produce Saleable Plasterboard." (GA)

> **Response:** This change in the benchmark units was inadvertently left out of the second 15-day changes to the regulation, but will be incorporated when we make further changes to the regulation sometime next year. The units have been changed in the Mandatory Reporting Regulation, which is the basis for allocation, so the oversight will not affect plaster board manufacturing allocation.

C-46. Comment: The Gypsum Association wants to ensure that the base year that ARB selects to allocate 2013 allowances for each gypsum board manufacturing plant reflects a fair and reasonable production level. The base year should acknowledge the current economic recession, its impacts on the gypsum board industry, and the impact on allocations that will occur when idled capacity is brought back on line at a future date. The proposed regulations do not appear to address this very important issue. Data on shipments of gypsum board to locations in the State of California for the period 2005 to 2010 points out the precipitous decline in shipments and reinforces the need for ARB to be judicious when it establishes a base year for gypsum board manufacturing facilities located in the State of California. The Gypsum Association requests further information from ARB on whether or not this base year has been determined for 2013 and would value the opportunity to enter into discussions with ARB regarding the importance of setting an achievable allocation for 2013 and years beyond. (GA)

> **Response:** This comment falls outside the scope of the first 15-day changes to the regulation. For information on the methodology for calculating any year's allocation, see sections 95870(e), 95890, and 95891.

Glass

C-47. Comment: ARB has established a product output based allocation calculation that is based on a single year of production data (specifically, two years prior to the budget year for which the calculation is being performed) in section 95891(b). We understand this allocation will subsequently be subject to a "true-up" four years into the program (starting in 2017). We ask that ARB confirm that flat glass manufacturers will not be penalized because the product-output-based allocation methodology for the "true-up" is based on a single year of production. Specifically, all flat glass furnaces must periodically undergo "hot" repairs during which time the furnace remains operational at a high temperature but there is no glass production. As currently drafted, it appears that the Cap and Trade Rule would preclude flat glass plants from receiving any allowances during these periods because of the lack of any actual glass production. For this reason, Guardian urges ARB to add a factor to the product-output-based "true-up" specific to the flat glass industry in order to account for the emissions from the fuel combustion during the time period in which the furnace is idled but not shut down. Such a factor could be based on the fuel benchmark used for the fuel portion of the thermal energy-based allocation methodology multiplied by the actual amount of fuel burned during the hot hold period. (GIC)

> **Response:** In the second 15-day changes to the regulation, we modified section 95891(b) further to clarify our approach. $O_{a,t}$ is replace by $O_{a,initial}$, which will be calculated by the Executive Officer as the output in year t-2 as reported to ARB. $O_{a,trueup}$ adjusts for any output in year t not properly accounted for in prior allocations. This modification to the added "true-up" term ($O_{a,trueup}$) for adjusted outputs not properly accounted for in prior years' allocations in the equation for calculating allocations under section 95891, together with the annual updating of product outputs, adequately address fluctuations in production.
>
> Section 95891(a) was updated to indicate that the choice of allocation methodology is based on classification of "activities" rather than "industries" in

Tables 8-1 and 9-1. This change clarifies that a facility within a given industry may conduct multiple activities, and the operator of a facility may receive allocation under both the product-based and energy-based allocation methodologies (based on the assigned allocation approach for each separate activity). However, the glass production benchmarks were set after consideration of the routine maintenance and repair events that the commenter outlines. Therefore, we did not add allocation based on the period where the furnace is idled but not shut down, since the benchmark incorporates data analysis of typical operations, including maintenance shutdowns. No allocation is specifically provided for periods when emissions occur but production does not, since this would be an incentive to increase emissions.

C-48. Comment: GANA re-states its understanding of and support for using calendar years 2005-2007 as a basis for developing the industry average CO_2 emission intensity benchmark for the flat glass industry because these years preceded the current economic downturn and were less affected by the unusual operating conditions necessitated by that downturn. (GANA2)

Response: We thank you for your support of our approach and agree that we selected an appropriate and representative benchmark for flat glass production.

C-49. Comment: Leakage Risk and Product Based Benchmark. As currently proposed, the flat-glass industry benchmark is based on only the three flat glass furnaces in California which includes two air/fuel-fired regenerative furnaces and one 100 percent oxyfuel-fired furnace. The 100 percent oxyfuel furnace design is not widely employed in the flat glass industry. The inclusion of that one oxyfuel-fired furnace in an average benchmark consisting of only three plants, however, pushes the benchmark lower to a degree that disproportionately impacts the PNA air-fired regenerative furnace which is one of only two remaining in California.

PNA is positioned to make a significant investment in the Lathrop facility but cannot assume the additional risk of increased compliance costs or the technical risks of conforming to the oxyfuel furnace design which CARB has identified as a low GHG emitting technology for flat glass production. PNA's planned investment for the Lathrop site includes the installation of an on-line chemical vapor-deposition coating process. There are only nine on-line TCO coated glass production plants in the world, and PNA's parent company runs six of them, two of which are in the U.S. PNA is not aware of any on-line TCO glass production process existing on an oxyfuel-fired furnace. PNA is not prepared to assume the risk of producing on-line coated glass on an oxyfuel-fired furnace and so must assume the additional costs of the cap and trade program in order to continue to operate in California, or choose not to invest further in California and produce the coated glass product at another site outside of California or outside the US. PNA proposes an alternative benchmark which can be applied to on-line coated glass products. Specifically, PNA proposes that the current benchmark already defined for flat glass production in the 15-day changes (0.471 metric tonnes of CO_2eq/ton of glass draw) be applied to all glass product not coated with an on-line process, and that a new benchmark be developed by taking 90 percent of the average CO_2 emission intensity (in metric tonnes / ton of glass draw) of the two air-fired regenerative furnaces in California and apply it to the tons of coated glass produced with an on-line coating process. The cap adjustment factor and the industry assistance factor would remain the same for both products. The result would look something like this:

Allocations in budget year =
[(Output * Bl * c * AF) + (true up formula)] (uncoated glass Production)+ [(Output * B2* C * AF) + (true Up formula)] (0n-line coated glass production)
Where, Bl = existing benchmark for flat glass production = 0.471 metric tons of CO_2eq/ton of glass draw and B2 = benchmark for on-line TCO glass production

This approach is consistent with the CARB benchmarking approach and at the same time helps to mitigate some of the risks involved with investments in the production of on-line coated glass products in California that can be used for energy efficiency and renewable energy applications. (PNA)

> **Response:** We did not develop a separate benchmark for TCO glass production at this time since there is no current TCO production in California. We will continue to work with the industry on this issue in the future to ensure that benchmarks are developed for new products newly manufactured in California, that leakage risk is minimized, and that the correct incentive is created for investment in efficient production in California.

C-50. (multiple comments)
Comment: GANA must reiterate its concerns outlined in its comments submitted on December 15, 2010 and in a conference call with CARB staff on June 3, 2011 about the small number of flat glass sites used as a basis for the flat glass industry benchmark in the California Cap and Trade program. There are only three flat glass sites in California —two of them are regenerative furnaces, and one of them is an oxy-fuel fired furnace design. This small number of sites (3) is not representative of normal operating conditions of the industry as a whole in the US which presently includes 30 flat glass lines. Such a small sample artificially skews the California benchmark, pushing it lower than a true industry average and thereby disproportionately impacts the remaining regenerative flat glass sites in California. For these reasons, GANA once again encourages CARB to consider a more representative national carbon emission intensity benchmark which the flat glass industry estimates, based upon its experience nationwide, to be more on the order of 0.5 metric tonnes of CO_2 eq/short tons of glass draw rather than the 0.471 metric tonnes of CO_2eq /short ton of glass draw currently proposed in the 15-day modification package. (GANA2)

Comment: PPG endorses, and hereby adopts as if set forth in full, the comments of GANA regarding the product output-based emissions efficiency benchmark for the flat glass industry (see section entitled “Flat Glass Industry Benchmark” in GANA letter to CARB, dated August 11, 2011). CARB has recognized the vulnerability of the flat glass industry to emissions leakage, and the use of an artificially low benchmark for the industry will only serve to increase compliance costs, which will in turn promote rather than prevent such leakage. The proposed benchmark in Table 9-1 of the Regulation was based on a non-representative cross-section of the flat glass industry, namely three plants in California. There are many more flat glass plants operating in the United States, with which the three California plants must compete. To ensure the continued competitiveness of the California plants and to avoid emissions leakage, it is important that the data source for the benchmark be representative of the domestic flat glass industry as a whole. The use of a broad-based benchmark will be even more important if and when CARB links its GHG emissions trading system with others across the country. PPG endorses GANA's proposal for a revised benchmark of 0.5 metric tons of CO_2E per short ton of flat glass pulled. (PPG1)

> **Response:** We believe that benchmark stringency should reflect the emissions intensity of highly efficient, low-emitting facilities within each sector. The benchmarks will incentivize continued production and improved emissions efficiency from all facilities in California. We analyzed all credible data available iteratively in deriving product benchmarks. On a case-by-case basis, national data were considered in developing the benchmarks, but most frequently national data was used as a check for the benchmark developed using California facility data. We believe the allocation approach creates the correct level of compensation to minimize leakage as required by AB 32.

C-51. Comment: In the current 15-day modification of the Regulation, the product output-based allocation calculation relies upon only one year of production data (specifically production in year t-2, two years prior to the budget year for which the calculation is being performed) and then is reconciled later in the program with the true-up factor. GANA emphasizes that in order for the true-up factor to fit its intended purpose, it would need to begin in budget year 2015 to reconcile 2013 actual emissions with the 2011 emissions used to calculate allocation in 2013. However, in any case the proposed true-up factor will only account for changes in emissions that are directly linked to production and not those emissions that are needed to keep the glass furnace hot during hot-holds or start-ups and shut-downs associated with cold repairs. GANA stresses and seeks confirmation from CARB that neither a cold repair nor a hot-hold situation would constitute a site "shut down" under the Cap and Trade program. Cold repair periods, during which time standard refractory replacement and maintenance activity take place, do not represent an intention by the manufacturer to halt production, but represent a standard maintenance activity in the flat glass industry. During a hot-hold situation, up to 45 percent of the total gas burned during normal operations is needed just to keep the furnace hot with no glass being pulled. Similarly for warm-up and cool-down periods associated with cold repairs during which time fuel will be burned while no glass is being pulled. As the rule is currently drafted, flat glass sites would have a compliance obligation for the emissions during these idling and warm-up/cool-down periods, but would not receive any allowances for these periods because the product output based allocation methodology looks at a single year of production, and there would be no production during these periods. To address this inequity stemming from production disruptions inherent in flat glass manufacturing, GANA requests that a factor be added to the existing product output based "true-up" factor specific to the flat glass industry to account for the actual emissions from the fuel combustion during the time period in which the furnace is idled but not shut down. GANA further requests that this factor be based on the fuel benchmark used for the fuel portion of the thermal energy based allocation methodology multiplied by the actual amount of fuel burned during the hot-hold period. (GANA2)

> **Response:** We agree that neither a cold repair nor a hot-hold constitute a site "shut down." The glass production benchmarks were set after consideration of the routine maintenance and repair events that the commenter outlines. We did not add allocation based on the period where the furnace is idled but not shut down since the benchmark incorporates analysis of data of typical operations, including maintenance shutdowns. No allocation is specifically provided for periods when emissions occur but production does not, since this would be an incentive to increase emissions.

C-52. Comment: ARB's public record for the development of the GHG intensity baseline for the container glass manufacturing industry indicates a preference towards oxy-fuel furnace technology and their associated greater GHG emissions, in comparison to regenerative furnaces. The issue stems from ARB's limited understanding of the different glass melting furnace designs and the total energy requirements associated with each. ARB stated during discussions with O-I regarding the establishment of the intensity baseline that their analysis of the total energy requirements for the different furnace technologies had been fully considered and was based on the data that was collected from the container glass manufacturing facilities. The data that ARB collected did not contain the specificity which would allow that level of analysis. The data request asked only for total facility electrical consumption. O-I is concerned that the lack of understanding regarding the total GHG footprint of the different furnace technologies, rewards oxy-fuel designs, penalizes regenerative furnaces, results in an increase in total California GHG emissions and acts as a detriment to the environment. Although oxy-fueled furnaces will demonstrate a slightly lesser GHG emission footprint in direct emissions due to a lower fossil fuel combustion rate, once the indirect GHG emissions associated with the electricity requirements for the production of oxygen is included, the GHG emission gap is at a minimum, eliminated. To alleviate this inconsistency with the intent of AB32, ARB needs to include the indirect GHG emissions associated with electrical consumption required to generate oxygen for an oxy-fuel furnace when establishing the intensity baseline, or alternatively bifurcation of the oxy-fuel and regenerative glass furnace types. (OWENSIL2)

> **Response:** We remain concerned about differentiating product benchmarks by process type or technology. Our goal is to remain neutral to technology choice to allow for choices that reduce greenhouse gases. We believe that the focus of benchmarking under cap-and trade program is to create the correct incentive for California facilities to reduce GHG emissions and protect them from leakage. This means that, in most cases, it is appropriate to avoid benchmarks differentiated by technology, fuel mix, facility size and age, climate

circumstances, or raw material. Ensuring that all GHG emissions-abatement options remain viable is an integral part in our development of product benchmarks.

We do not believe it is necessary to add provisions to the regulation to account for indirect carbon costs associated with purchased electricity at this time. In the program framework, an adjustment factor was not made for power purchased in establishing the product-based benchmarks. This is because purchased power may not create an indirect carbon cost in all California utility service territories. It is our goal to see a carbon price properly embedded in all utility rates. If and when this occurs, the compensation for these indirect carbon costs could be incorporated into the product benchmarks (or reductions in these costs created in some other fashion) to help minimize leakage. We will revisit this issue once the CPUC proceeding addressing utility costs and revenue issues associated with greenhouse gas emissions concludes.

C-53. Comment: NAIMA had originally urged CARB to rely upon national emissions analysis for determining a benchmark for the fiber glass industry, but CARB indicated it wanted to rely upon California emissions data. CARB did agree, however, to consider 2009 California data which NAIMA provided to CARB in its February 16, 2011, letter. During the March 17, 2011 meeting, CARB indicated that it now might consider using national data to set the benchmark. CARB agreed that it would obtain direction from its Board as to whether it could rely upon national data as opposed to California data. CARB agreed to communicate to NAIMA when it has a final decision on use of national data. If national data is allowed, CARB indicated it would like national data by facility. Before NAIMA could agree to provide national data by facility, it would need to know the elements of specificity required for each facility. CARB has agreed to provide those elements of specificity to NAIMA, but NAIMA has yet to receive that information. CARB's current proposal seems to be based on California numbers. (NAIMA2)

Response: We recognize that, from a statistical point of view, averaging data from three or two facilities has limitations. In developing benchmarks for industries with a low number of facilities in California, we considered different data sets, including national data, to check the appropriateness of the benchmarks. However, we have the greatest confidence in the California data set, and from the perspective of fairly allocating free allowances to California facilities to minimize leakage risk, we believe the reliance on California facility data is appropriate.

C-54. Comment: Unlike most other manufacturing facilities, flat glass furnaces must operate continuously, even when no glass is being produced. In any given compliance period, it is possible that a flat glass furnace may have a significant, unavoidable gap in glass production due to a "hot hold" or a furnace rebuild. Moreover, in the case of a "hot hold," the lack of production will be accompanied by significant CO_2E emissions from the fuel combustion needed to maintain enough heat in the furnace to preserve its structural integrity. In a furnace rebuild scenario, the furnace cool-down period prior to the rebuild and the start-up afterward will also result in CO_2E emissions without corresponding glass production. Thus, while PPG supports the proposed product output-based formula for direct allocation of GHG allowances to the glass industry in section 95891(b), that formula must include some adjustment mechanism to avoid the substantial adverse impacts which would otherwise result from the exclusive use of a product output-based formula for years when significant gaps in production occur due to "hot holds" or furnace rebuilds. Those adverse impacts would be magnified by the fact that the year for which the allowances are allocated would not be the same as the base year used in the allocation calculation, leading to the possibility—even probability—that an allocation of allowances calculated using a base year with gaps in production would not be sufficient to cover the compliance obligation for the later, full-production year for which the allowances are allocated. To resolve this issue, an additional formula for "hot hold" and furnace rebuild periods must be used to supplement the product output-based allocation formula. PPG endorses the resolution proposed by GANA in its August 11, 2011 comments to CARB—namely the substitution of a fuel benchmark from the energy-based allocation formula in section 95891(c), multiplied by the quantity of fuel actually combusted in the furnace during any "hot hold" period or furnace rebuild, instead of the product output-based formula for that period. The allowances resulting from that fuel-based formula for non-production periods would then be added to the allowances resulting from the application of the product output-based formula to the remainder of the year when glass was being produced. PPG recognizes that this approach may complicate the equation for allocation of GHG allowances when the base year used in the equation includes a "hot hold" or furnace rebuild. However, some accommodation must be provided in section 95891(b) to avoid the artificial reduction in allowances that would otherwise result from the exclusive use of a product output-based approach when there are significant, unavoidable gaps in glass production in the base year for the calculation. To leave the provision as currently proposed would ignore the realities of flat glass production and would impose an unfair and unworkable compliance burden on the flat glass industry. (PPG1)

> **Response:** The glass production benchmarks were set after consideration of the routine maintenance and repair events that the commenter outlines. We did not add allocation based on the period where the furnace is idled but not shut down since the benchmark incorporates analysis of data of typical operations, including maintenance shutdowns. No allocation is specifically provided for periods when emissions occur but production does not, since this would be an incentive to increase emissions.

Hydrogen

C-55. (multiple comments)
Comment: The benchmark proposed for hydrogen production by "Industrial Gas Manufacturing" employs the standard product-benchmark method described conceptually in Appendix B of the 15-Day Modification Package. The gaseous hydrogen benchmark is derived from emissions and production data from only six independent hydrogen production plants (including two that produce liquid hydrogen

and are inappropriate for inclusion in the gaseous hydrogen benchmark basis) and ignores the 20 other refinery-owned hydrogen plants operating in California. Discussions with CARB staff confirmed the emissions intended to be considered in the hydrogen benchmark include combustion emissions from producing process heat and steam within the hydrogen plant; process and combustion emissions resulting from hydrogen production itself; and combustion emissions from production of electricity within the hydrogen plant. Staff indicated that the benchmark derivation is to take into account (deduct) any export of thermal energy and electricity, where appropriate. CARB staff acknowledges that it does not yet have the complete hydrogen production and emission data from even the six plants considered that are needed to define the hydrogen benchmark and thus the benchmark value of 8.51 allowances per ton of hydrogen is incorrect. In addition to excluding industrial gas manufacturing plants that produced only liquid hydrogen from the database used to develop the gaseous hydrogen benchmark, CARB must include the 20 gaseous hydrogen plants in the state owned and operated by refiners. Because the current benchmark is based on a highly biased data set excluding the majority (20 of 24) of gaseous hydrogen plants in the state, it fails to accurately reflect the true emissions associated with gaseous hydrogen production in California and cannot be considered to be an equitable benchmark. Instead, the current benchmark relies predominantly on the emission intensity performance of the four most modern and efficient plants (industrial gas manufacturing facilities) and then imposes a “performance challenge” upon that “top quartile” of facilities. This effectively penalizes these facilities and their owners for having made material investments in more efficient production technologies—a fundamental premise of the Cap and Trade allocation program as outlined in Appendix J. Again, a correct and equitable benchmark must include all hydrogen production units in California. We would further note that, while CARB staff has issued a data collection request to industrial gas producers to augment existing data, it has not yet initiated a comparable request to the refinery-owned/operated hydrogen production facilities in order to develop a representative benchmark value. This request must be issued immediately so that an accurate and equitable benchmark can be incorporated into the Cap and Trade Regulation. Air Products recommends that CARB expand the database used to calculate of the hydrogen benchmark to include all hydrogen production in the state—both refinery-owned and “independent” producers. If this requires additional data from the refinery hydrogen producers, CARB must make a timely information request to the impacted facilities. (APC2)

Comment: The product-based benchmarks in Table 9-1 are not at all transparent. WSPA has many questions on how benchmarks were calculated. For example what assumptions were made to calculate the H2 plant benchmark? Was pure H2 production assumed? WSPA recommends that ARB conduct stakeholder workshops to provide transparency to the benchmarking process. (WSPA3)

Comment: To avoid market distortions, it is important that the allocation benchmarks assigned by the California Air Resources Board (ARB) for gaseous hydrogen are equitable and apply to all gaseous hydrogen production facilities. ARB has proposed a benchmark for gaseous hydrogen production based on the performance of just six of

26 hydrogen production facilities in the state (and two of those six have significant liquid hydrogen production activities, which ARB is considering a separate product). ARB should calculate the benchmark based on the performance of all 26 gaseous hydrogen plants in the state and expand the hydrogen production survey recently sent by ARB staff to the independent hydrogen producers to include all hydrogen production facilities. A benchmark based on the full dataset of production facilities will be a more representative product benchmark. This, in turn, will result in a more accurate and equitable benchmark. Industrial gas manufacturers operate plants that supply hydrogen in gaseous and liquid form to petroleum refineries. In many cases, petroleum refiners operate their own hydrogen plants within their facilities, and thus many refiners have a choice whether to purchase hydrogen from an industrial gas manufacturer or to use their own in-house capacity to produce hydrogen. ARB's goal in designing the Cap-and-Trade provisions for hydrogen production facilities should be to avoid creating market distortions. Market distortions are undesirable for two reasons. First, by creating market distortions, the State in effect picks winners and losers in the market, thus violating AB 32's directive that ARB design the cap-and-trade regulations to be "equitable." Second, market distortions may result in increased emissions, thus undercutting AB 32's objectives. It is desirable that the allocation benchmark is equitable – the same benchmark should apply to all hydrogen production regardless of whether the hydrogen is produced within a refinery complex or produced by an independent producer and supplied across the refinery fence. We urge ARB to clarify that the hydrogen production benchmark will be based on emissions data from all hydrogen production facilities. This should be reflected in Appendix B: Sector Details for Hydrogen Production. ARB has proposed to collect data from all facilities and exclude the Aggregation of Units of different source categories, as stated in section 95114 and 95115 of the "Proposed Amendments to the Regulations for the Mandatory Reporting of Greenhouse Gas Emissions." The Panel encourages ARB to collect this information and incorporate the data reported from all facilities into the product benchmark as soon as possible. ARB should also clarify references to hydrogen production and industrial gas production facilities throughout its various draft regulations and supporting documents (Example, Table 9.1. Page A-114) so that it is clear that the allocation benchmarks apply to all gaseous hydrogen production facilities. (IGPACC)

Comment: The allocation methodology that will provide the most accurate and most equitable benchmark is the Carbon Weighted Barrel (CWB) approach outlined in Appendix J of the Staff Report for the December 2010 rulemaking. As the European Union concluded in its Emissions Trading Scheme (EU ETS) Phase 3 rulemaking, a consistent hydrogen production benchmark can be applied to hydrogen production facilities in the refining sector in combination with the overall refining benchmark, which results in a consistent performance target for all hydrogen producers. We recognize that the ARB staff needs time to conduct more comprehensive data collection and analysis to implement the CWB method, and therefore, an interim method will be required for the first compliance period of the Cap and Trade program while this data analysis is undertaken. In order to ensure a long-term, equitable benchmark, ARB should make a regulatory commitment to implement the CWB method by the beginning of the second compliance period. This will help provide certainty, promote investments in California within our industry and prevent inequity. ARB should indicate its intent to implement the CWB method by the beginning of the second compliance period in Appendix B: Sector Details for Hydrogen Production. (IGPACC)

Comment: Given the relatively small number of liquefied hydrogen production facilities in California, establishing a benchmark for an "efficient facility" is impractical. Praxair suggests that CARB use an individual facility's verified emissions associated with liquid hydrogen product output reported pursuant to the Mandatory Reporting Rule (MRR) and the GREET Model to establish a benchmark for liquefied hydrogen production. (PRAXAIR2)

> **Response:** We recognize that equity issues exist between allocation to third-party production of hydrogen gas sold to petroleum refiners and refinery-owned hydrogen production. We believe that employing the CO_2 Weighted Tonne (CWT) approach for the refining sector is the best way to address this issue. We present separate benchmarks for hydrogen gas and liquid hydrogen based on the amount produced in Table 9-1 in section 95891(b). In the second 15-day changes to the regulation, we modified the hydrogen production benchmark to match the EU ETS hydrogen benchmark for both liquid and gaseous hydrogen. As noted in Appendix B to the First 15-Day Change Notice, this benchmark was based on a value reflecting the average greenhouse gas performance of the 10 percent best performing installations in the EU. Use of this benchmark should provide equitable treatment between refinery-owned and independent hydrogen producers once the refineries are covered under the CWT approach. We recognize that production of liquid hydrogen could potentially create indirect carbon costs for the emissions associated with purchased electricity. We recognize that purchased electricity used in the production of liquid hydrogen could potentially create indirect carbon costs. We will revisit the issue of carbon costs embedded in purchased electricity once the CPUC proceeding addressing utility costs and revenue issues associated with greenhouse gas emissions concludes.

C-56. (multiple comments)
Comment: The International Council on Clean Transportation (ICCT) recommends establishing benchmarks for transportation hydrogen use. This value will not by itself pay for installing new hydrogen stations, but can play an important role in narrowing the operating stage profitability gap for hydrogen stations during the critical early ramp-up of fuel cell electric vehicles. (ICCT3)

Comment: Hydrogen fuel cell electric vehicles could suffer an unfair playing field in Phase I of Cap and Trade because the full “well-to-wheels” emissions are subject to Cap and Trade, whereas petroleum burned in internal combustion engines is not. CARB can remedy this situation and encourage development of an advanced transportation technology through free GHG allowances. We recommend awarding these allowances based on avoided vehicle petroleum combustion emissions. ICCT calculates the avoided emissions value for distributed zero carbon renewable hydrogen at 31.6 tons GHG allowances/ tons renewable H28 in Cap and Trade phase I. CARB has proposed a value of 8.62 tons GHG allowances per ton centrally produced hydrogen using steam methane reforming. For centrally generated hydrogen, a smaller adder for hydrogen used for transportation purposes should also be added based on CARBs LCFS methodology. Future updates can be made as CARB covers vehicle tailpipe emissions and eliminates free Cap and Trade allowances for petroleum production and refining subsidy. (ICCT3)

> **Response:** We did not offer incentives for individual greenhouse gas-reducing technology, such as hydrogen for transportation applications, through free allocation. The incentive for greenhouse gas reduction created by the cap-and-trade program comes through carbon pricing rather than through free allocation.

C-57. Comment: The benchmark for hydrogen production should not be reduced to account for heat or steam sold by a hydrogen production facility. ARB staff comments on previous discussion drafts have made reference to adjusting benchmarks to account for heat purchased and sold by facilities. Hydrogen plants typically produce heat in the form of steam for their refinery customers. Petroleum refiners will receive allowances either in proportion to their output or their historical emissions, and thus will receive allowances for steam production that is used in the production of petroleum. If industrial gas manufacturers do not receive allowances for the production of all inputs to the petroleum refining process, including steam, market distortions may result, and refiners may have an incentive to use less efficient sources of steam production. (IGPACC)

> **Response:** In the second 15-day changes to the regulation, we modified the hydrogen production benchmark to ensure equity between merchant hydrogen plants and refinery-owned hydrogen production allocated to using the “Carbon Dioxide Weighted Tonne” metric. However, we believe that all sales of steam should reflect a carbon price. We encourage merchant hydrogen production facilities to include a carbon adder in the price of steam sold to refineries in the future.

C-58. Comment: We recommend establishing a separate benchmark for transportation hydrogen production to recognize both the displaced GHG emissions due to fuel cell vehicles and the absence of a cap on surface transportation petroleum combustion GHG emissions initially. This benchmark should be based on the displaced CO_2 from petroleum, using LCFS values and recognizing the improved efficiency of fuel cell vehicles compared to petroleum fueled vehicles as established in the LCFS. ARB should establish a straight-forward allowance application process in conjunction with the LCFS, recognizing that a number of potential hydrogen fuel suppliers are small businesses without the resource to “opt-in” the Cap and Trade. (KUSTIN15)

> **Response:** We did not offer incentives for individual greenhouse gas-reducing technologies, such as hydrogen for transportation applications, through free allocation. The incentive for greenhouse gas reduction created by the cap-and-trade program comes through carbon pricing rather than through free allocation.

C-59. (multiple comments)
Comment: Both liquefied hydrogen and gaseous hydrogen are often produced at the same facility. Gaseous and liquefied hydrogen production have differing emissions intensities. Praxair believes that it will be important to apply two benchmarks to a facility that produces both gaseous and liquefied hydrogen. The liquefied output should receive allocations based on the facility's verified emissions that are attributable to liquefied hydrogen. The gaseous output should receive allocations based on the gaseous hydrogen efficiency benchmark. (PRAXAIR2)

Comment: Liquid hydrogen should receive an independent benchmark. ARB has recognized in the updated draft documents (Annex B and the Proposed 15 Day Modifications on Subchapter 10) that liquid hydrogen is a different product from gaseous hydrogen used in refining applications. Liquid hydrogen is produced using different equipment and processes, requires more energy to produce, and is readily transportable across California borders and it requires additional production methodology and equipment. Further, liquid hydrogen production has a material indirect GHG emission footprint due to the significant electricity consumed in the liquefaction process. For these reasons, liquid hydrogen should be treated as a distinct product with its own unique product benchmark. (IGPACC)

> **Response:** We established a separate benchmark for liquid hydrogen. We recognize that purchased electricity used in the production of liquid hydrogen could potentially create indirect carbon costs. We will revisit the issue of carbon costs embedded in purchased electricity once the CPUC proceeding addressing utility costs and revenue issues associated with greenhouse gas emissions concludes.

Oil and Gas

C-60. (multiple comments)
Comment: With respect to oil and gas (“upstream petroleum and natural gas operations”) a benchmark that differentiates between operations that produce “light” and “heavy” crude oil has serious concerns. As presented, the proposed API gravity-based approach does not consider EOR production processes. If enacted it will,
(i) significantly and adversely affect California producers relative to out-of-state oil producers, thus violating the intent to protect against “leakage,” (ii) create wide disparity in free allowance allocations among in-state producers, and (iii) potentially disadvantage future light crude oil production growth in the state. WSPA provides a detailed analysis of these issues in Attachment A and we invite follow-up discussions in the near future. WSPA recommends that ARB return to their initial approach that proposed different benchmarks for thermal and non-thermal operations. WSPA supports the thermal/non-thermal methodology submitted by WSPA to ARB staff. (WSPA3)

Comment: ICCT recommends a flat benchmark of approximately 5 grams CO_2/ MJ for both light and heavy crude production. (ICCT3)

Comment: ARB should adopt the thermal/non-thermal benchmark for oil and gas production that recognizes California's unique products which are a function of the geology and the type of resource. The proposal reversed the December 2010 rulemaking which proposed a thermal/non-thermal benchmark for oil and gas production in favor of light and heavy crude oil because it more precisely fit the definition of a product-based benchmark. Sector specific benchmarks must be based on technically sound metrics developed through a fair public process that recognize California's unique industry footprints. The ARB selected a light and heavy crude oil benchmark in its proposal because it is more precisely "product based." This shift from the thermal/non-thermal benchmark adopted in the December 2010 rule ignores key characteristics of California's energy resources and neither the approach nor the calculations supporting the benchmark were vetted with stakeholders or industry experts. The ARB should be transparent in the development of its benchmarks. The procedure establishing the benchmark should be published and vetted with stakeholders prior to adoption. It should base the benchmark on verified emissions data from 2008 and 2009, collected with all parties using the same methods under the Mandatory Reporting rule, so that it is comparable. (CHEVRON3)

> **Response:** The activities under crude petroleum and natural gas extraction were changed from "Heavy (API < 20) Crude Oil Extraction" to "Thermal EOR Crude Oil Extraction" and "Light (API >= 20) Crude Oil Extraction" to "Non Thermal Crude Oil Extraction." The product benchmarks are allowances per barrel of thermal crude oil equivalents and allowances per barrel of non-thermal crude oil equivalents, respectively. As noted in Appendix J to the Staff Report, although we prefer to apply a "one product, one benchmark" principle, an exception was made for oil extraction because non-thermal alternative techniques are not usually substitutable in the wells where thermal EOR is applied.

C-61. Comment: In establishing the benchmark for credit allocation to oil and gas production we have encountered issues that remain unresolved. For example, there exists an apparent erroneous bin assignment under CARB's proposed Heavy/|Light Crude Oil approach. This subjective assignment will serve to skew the data for both categories causing unintended consequences for both categories of crude. Moreover, split field designation using a 50 percent approach for mixed fields is technically inaccurate and would lead to inappropriate and largely inaccurate benchmarks. Despite meeting with staff, and outlining the potential fallout from these inaccuracies, we are still unsure if and how corrections might be made to the final draft. We are further concerned about how CARB will be verifying accuracy of benchmark at the onset of the program and going forward and we wonder how CARB will monitor the accuracy of the benchmark in the future (especially in consideration of difference between the MRR facility definition and what is conventionally used in California). (CIPA)

> **Response:** We addressed the "bin" data issue the commenter refers to in development of the final benchmarks. We will continue to work with stakeholders

going forward to monitor the impacts of the benchmarks selected and ensure the amount of free allocation is sufficient to minimize leakage.

C-62. Comment: We are unconvinced that heavy and light crudes are fundamentally different products and therefore oppose the more than six times higher benchmark for heavy crude extraction. This is an unnecessary subsidy of high carbon crude, which results in higher GHG and criteria pollutant emissions in the field and at the refinery. It creates a perverse incentive to increase the use of heavy crude feedstocks in California. We recommend a flat benchmark and the potential to award bonuses for implementation of efficiency measures identified by CARB and for demonstrating renewable technologies (e.g. renewable energy for steam and electricity production). This will give larger emitters the opportunity to close the gap in both directions (by cutting emissions and earning bonus allowances). (KUSTIN13)

Response: The activities under crude petroleum and natural gas extraction were changed from “Heavy (API < 20) Crude Oil Extraction” to “Thermal EOR Crude Oil Extraction” and “Light (API >= 20) Crude Oil Extraction” to “Non Thermal Crude Oil Extraction.” The product benchmarks are allowances per barrel of thermal crude oil equivalents and allowances per barrel of non-thermal crude oil equivalents, respectively. As noted in Appendix J to the Staff Report, although we prefer to apply a “one product, one benchmark” principle, an exception was made for oil extraction because non-thermal alternative techniques are not usually substitutable in the wells where thermal EOR is applied.

Paper

C-63. Comment: Resolution 10-42 directs that allowances be allocated under the product-based approach. We urge the Board to assign emissions intensity benchmarks in a way that acknowledges unique differences between facilities, and which is consistent with a facility’s current activity. PGPPC is concerned that ARB is proposing to assign our Oxnard facility annual GHG allowances based on a product benchmark established by a facility in our industrial category which produces fundamentally different products, produced using a fundamentally different technology, and with a subsequent emissions intensity that is not comparable to or demonstrably similar to our own. Our manufacturing process and equipment is specifically designed to deliver targeted consumer preferred product-based benefits and differs from others in our industrial sector. The energy utilization and subsequent emissions intensity follows as a natural consequence from the unique design of our manufacturing process which is designed to deliver preferred differences in finished product performance. Based on calculation methods identified in Appendix B - Development of Product Benchmarks for Allowance Allocation, and emissions data currently available through ARB, there is a significant difference between our Oxnard Facility and other sources in our industrial category. The difference in emissions intensity and product attributes and performance provides compelling data that our Oxnard Facility is substantially different and should be evaluated on its own merit to establish a facility specific emissions intensity product-based factor. We believe our facility located in Oxnard should be assigned an emissions intensity product benchmark unique to us, and not the same as the (one other) source in California within our same manufacturing industrial category. (PGPPC)

> **Response:** We worked with stakeholders to assess different technologies used to manufacture tissue (e.g., conventional and through air drying (TAD) processes), and found that final products that use TAD are lighter, fluffier, and more absorbent. However since the functionality of the product is still the same even though the quality is different, we believe that it makes sense to group tissue products regardless of the technology. We intend to continue working on the tissue sector to further investigate technologies and review units and numbers of final products for their benchmark.

C-64. (multiple comments)
Comment: AF&PA supports the use of actual emissions as the basis for allowance allocations. Our concerns with product-based GHG efficiency benchmarks center on the fact that product-based benchmarks are complex and unworkable for our industry; they arbitrarily create winners and losers; and there is a large variation in products and processes making it likely that dissimilar processes will be in the same category. For example, medium mills manufacture medium; linerboard mills manufacture linerboard and can also manufacture medium as well; and gypsum facing board mills can typically also manufacture linerboard and medium. In California, there are 11 industry mills manufacturing a variety of products: linerboard, medium, tissues, towelettes, tube and core stock, gypsum facing, organic roofing paper, coated board, and coated boxboard. Perhaps more importantly, the industry's internal analysis of the allowance allocation method included in federal Cap and Trade legislation showed no correlation between GHG emissions and product type for the examined sectors of our industry. Rather than product type, our analysis shows that fuel type, and degree of integration and steam production, are the overriding factors that determine a facility's GHG emissions. In most cases, these factors are intrinsic to a facility's operations and cannot be changed without changing the basic nature and/or configuration of the facility.

CARB has inappropriately ruled out using at least two of the key factors that would yield the most reliable benchmarks, stating that "staff relied upon the 'one product, one benchmark' principle. This means that, in most cases, staff believes it is appropriate to avoid benchmarks differentiated by technology, fuel mix, size and age of the facility, climatic circumstances, or raw material quality" (emphasis added). We acknowledge that in California the inability to differentiate by technology may not be as significant an issue given the current configuration of existing mills. The forest products industry is the leader among all manufacturing sectors in the use of highly-efficient cogeneration technology to generate power and steam (also called Combined Heat and Power (CHP) technology). Virtually all AF&PA member facilities that generate electricity on-site do so using this technology. This is true in California as well, as three out of four AF&PA member mills that were included in the analysis to develop pulp and paper industry facility benchmarks and generate electricity use CHP technology and are highly efficient. Instead of rewarding them for this efficiency, they are penalized by receiving very low benchmarks. Further, because mills with CHP generate electricity on-site, they have relatively higher direct emissions and significantly lower indirect emissions associated with purchased electricity, resulting in lower total emissions. This is because mills with CHP generally do not need to purchase large amounts of electricity, and indeed can sell power to the grid. In fact, in California those same three mills sell power to the grid. Unfortunately, the methodology used to develop the CARB benchmarks does not properly include adjustments to reflect this emissions profile. Specifically, the methodology counts in the benchmark development emissions associated with electricity generated on-site, but not emissions associated with purchased energy.

Because, as stated, CHP mills' direct emissions are relatively high and indirect emissions are relatively low, this penalizes mills with CHP even though their total emissions are less than comparable facilities without CHP technology. The benchmarks are based on data from too few mills to be meaningful and only address a limited number of production activities within an NAICS sector. It makes no sense to develop a "benchmark" based on one facility, or even three facilities, as these are simply insufficient numbers on which to create a valid benchmark. We recognize that CARB has adopted a policy to develop product-based benchmarks, but it is incumbent on CARB to do so in a scientifically-defensible manner. Basing benchmarks on one or a few facilities does not meet that standard, especially when, as here, the mills have already incurred the expense and taken steps to improve the efficiency of their operations and reduce their GHG emissions. The benchmarks as applied to these mills penalize them for taking those steps. (AFPA2)

Comment: The proposed product-based benchmarks are not appropriate for the pulp and paper industry. They are not workable, they are determined by product type (which does not correlate with GHG efficiency in the industry), and CARB rejected two of the key factors that determine efficiency for industry mills—technology and fuel mix. Further, they are based on too few facilities to develop credible benchmarks, especially when weighed against the complexity and resources that will be expended to develop and implement the program, and do not account for new market entrants with production activities outside of the narrowly defined categories in Table 8-1. We urge CARB to abandon the benchmarks, and instead distribute allowances in proportion to the actual absolute emissions of the mills within the scope of the program. This would be easier to develop and implement, as mills are already reporting GHG data to CARB. Further, the overall decrease in the program cap ensures CARB will achieve the needed reductions from industry facilities, not GHG efficiency benchmarks assigned to individual industry facilities. (AFPA3)

Comment: We are concerned that CARB is proposing to use product based benchmarks as the basis of allowance allocations for the Paperboard sector. An industry-wide analysis of pulp and paper manufacturing showed no correlation between greenhouse gas emissions and product type. The Paperboard sector is one of 13 sectors contributing only 9 percent of the California GHG emissions (Appendix B, p. 11). To the best of our knowledge, we are the only mill in California that produces Iinerboard, and one of two mills that produces medium. Appendix B of the proposed rulemaking indicates that CARB's approach may be compared to the product benchmark work done in the European Union's Emissions Trading Scheme (EU ETS) for the paperboard sector. The EU ETS benchmarks reflect the average GHG performance of the 10 percent best performing installations. We cannot confirm how CARB developed the product benchmarks for the Paperboard sector because there is no supporting documentation provided in the proposed rulemaking. However, CARB did establish product benchmarks for both products made at the Ontario Mill, linerboard and medium. Since the sample size for these two products (one and two mills, respectively) is so small, we do not believe it is appropriate to establish product based benchmarks. It would be inaccurate to say that the proposed benchmarks reflect the average GHG performance of the 10 percent best performers, since there are so few mills in each of the product categories. In addition, in April 2011, the European Commission determined that where several products are produced at one location, it was not feasible to assign GHG emissions to individual products and therefore, those sites were not included in setting the benchmarks. Since the Ontario Mill produces multiple products, using the EU ETS logic, it would be inappropriate to establish product benchmarks based on data from this mill. Since the Ontario Mill is the only producer of linerboard, there would be no valid data to support a product based benchmark for this activity. Therefore, we support the use of actual emissions as the basis of allowance allocations. (TI)

> **Response:** There are five paper/paperboard mills that are covered under the cap-and-trade program. We contacted all five mills and gathered information about their products, technology, and cogeneration units—including the amount they sell to the grid. Final products were classified in four categories based on their characteristics. The benchmark calculation adjusts for electricity sold in order to account for carbon cost recovery through the price of power sold. We believe that no mills are unintentionally disadvantaged only because the sample population is too small, or because the paper sector is heterogeneous and runs cogeneration units. The allocation methodology is intended to reward efficient producers within a sector and to minimize leakage. We believe that allocation based on historical emissions, as one commenter suggests, is inappropriate to achieve these goals.

C-65. Comment: It is unclear from the wording of section 95891(a) if operations within a listed sector but not defined by a listed activity would receive allocations using the energy-based benchmark allocation methodology of section 95891(c) or if they would receive no allocations because their specific activity is not listed in Table 8-1. If the latter, CARB would be severely discouraging expansion of existing operations in the state of California. The vast changes made to Table 8-1 from the December 2010 Proposed Regulation to the July 2011 Discussion Draft creates this ambiguity, and AF&PA requests that CARB specifically address this concern by eliminating the specific activities in Table 8-1 (i.e., reverting back to the December 2010 proposal) or explicitly addressing operations that fall into the NAICS sector definitions and NAICS codes in Table 8-1 but not any of the activities listed in Tables 8-1 or 9-1. For our specific sectors, it is misleading that Table 8-1 currently implies that the entire NAICS classification for “Paper (except Newsprint Mills)” (322121) is defined by the one activity of “Through Air Dried Tissue Manufacturing” or that NAICS code 322130 is defined by only the three activities currently listed in Table 8-1. (AFPA2)

> **Response:** We clarified the distinction between “activities” and “sectors.” Activities listed in Table 8-1 but not listed in Table 9-1 will receive free allocation based on an energy-based benchmark specified in section 95891(c). The change made to Table 8-1 and 9-1 was to make clear the sectors and the activities that are eligible for assistance. We intended to ensure that listed activities covered the operations conducted by each industrial facility that is subject to the regulations. We do note that “air-dried tissue manufacturing” was changed to “tissue manufacturing,” which includes any type of tissue manufacturing.

C-66. Comment: I understand and appreciate CARB needing to establish a greenhouse gas benchmark for each type of industry to determine allowances. However, when the type of industry is a population of one (such is the case for our paperboard mills), then that is not a benchmark. Statistically, a pool of twenty should be used to develop such a starting point. Since there are not twenty similar industries in the State of California, then the data source should be enlarged to incorporate such a pool. This will be accomplished soon with the mandatory reporting on a national level. Once this data is collected, then it should be used to develop a benchmark. Using a population of one to develop a standard is onerous and burdensome to the facility that must find means to reduce its carbon footprint even though it may be the best in the nation. The cost of credits may outweigh the expected margin of the facility's profit, and cause them to shut down. (GPI2)

> **Response:** We believe it is consistent with the goal of AB 32 to include as many industrial sectors as possible under product-based benchmark to minimize leakage; free allocation is based on a product level that will be updated annually to ensure that the compensation is provided as production increases. The thermal-based benchmark does not have updating mechanism, and therefore does not guarantee free allocation in proportion to production level. For the sectors for which there is only one facility, the facility’s historical performance level is considered to be “best in class.” We will consider a revision to the benchmark in future rulemakings if new and better data, including national data, become available. At this point we are not aware of any robust national emissions intensity data set available for the paper sector.

C-67. Comment: As a facility in a highly trade exposed industry (paperboard), we are concerned that market prices for allowances at $25/ton and above are going to have a severe impact on our business. Since we are trade exposed, we cannot pass these costs onto our customers as we compete with firms outside the jurisdiction of ARB. To alleviate this potentially severe impact on our manufacturing business and the jobs we provide, we suggest that ARB look at the pricing impacts on highly trade exposed industries, potentially reducing or removing the cap adjustment factor for highly trade exposed industries or waiving it when a certain price trigger (e.g. $25/ton) is hit. The cap adjustment factor exceeds the growth expected in our industry, preventing us from keeping pace from an earnings perspective. It becomes a severe penalty as the price of allowances reaches $25/ton. Controlling the costs of the cap adjustment factor for our highly trade exposed industry is vitally important to allowing our industry to sustain its manufacturing operations and keep Californians employed. (GPI4)

> **Response:** The cap adjustment factor is one factor in the calculation of allowance allocation to industrial producers. Since the amount of allowances available for all emitters declines over time, the total number of allowances allocated to entities must decline as well. Therefore, the cap adjustment factor declines in proportion to the cap for most industrial producers. In some sectors, with high emissions intensity, high leakage risk and with process emissions as the majority of their total, the cap adjustment factor is approximately half of the overall cap decline. This is indicated in the second 15-day changes to the regulation, section 95891, where Table 9-2 was modified to define "sectors and activities associated with process emissions greater than 50 percent." For this reason, the cap adjustment factor is not triggered based on allowance price. Rather, we believe that there are abatement opportunities within acceptable price ranges. As a result, covered entities are able to purchase allowances from the allowance price containment reserve at fixed prices above where we believe trading activity will occur. This helps keep allowances prices within an established range. Our analysis of leakage risk took into consideration these design features, and we believe our allocation approach for industrial producers is sufficient to minimize leakage.

C-68. Comment: The benchmark for the Recycled Boxboard industry is based on recent data which includes early action projects. ARB has said that it would not penalize facilities for conducting early action projects and inspired facilities to begin reducing GHGs. Unfortunately, the recycled boxboard group is being penalized for conducting early action projects, as the results of these early action projects are being included in the benchmark. Furthermore, the data used for this benchmark is very limited and not statistically significant. As most of the recycled boxboard mills in the country reside outside California, ARB's approach makes it impossible to tell whether the California Recycled Boxboard group is operating better or worse than its national peers. This again creates a competitive disadvantage when California mills compete against its national peers. We ask that ARB reconsider the data it uses for this group and look into a national data set for the recycled boxboard group. We request that more recent data be omitted to provide reward for early action projects. We request that data prior to 2008 be included in order to develop a fair benchmark and improve the statistical significance of this benchmark. (GPI5)

> **Response:** We believe that benchmark stringency should reflect the emissions intensity of highly efficient, low-emitting facilities within each sector. Benchmarks were selected to reward early action projects, not to penalize them. However, in some sectors, there is only one facility in a benchmarked group. In this case, we

assumed that this facility was best-in-class and used their emissions intensity as a benchmark. This is the case with recycled boxboard sector. At this point, we are not aware of any robust national emissions intensity dataset available for the recycled boxboard sector. We will be able to compare California producers with national producers when data become available.

In considering the data available for determining a benchmark for producers, we typically relied on emissions data reported under MRR and consequently used production data voluntarily supplied by facilities for the same years. The MRR data were first reported for 2008 emissions. In some cases, ARB had conducted industry surveys or facilities had voluntarily reported to the California Climate Action Registry. In those cases, we had alternate data sets on which to rely.

Refineries

Support for EII

C-69. (multiple comments)
Comment: ARB should adopt the Energy Intensity Index (EII) based benchmark that meets the goals of AB 32 to reduce CO_2, reward early action, and not punish those that invest in their California refineries. The proposed "Simple Barrels" benchmark would promote leakage and simply does not achieve AB 32 goals, which were included in the statute, of rewarding early action at existing facilities. It also is not equitable to larger facilities that manufacture cleaner California fuels and other high value products such as lubricating oils, which serve global markets. ARB proposes to use a "simple barrel" approach because it is "product based." California makes unique demands of its refineries by requiring cleaner fuels which has, in turn, required more complicated operations that utilize much more equipment than typical refining operations. The simple barrel benchmark ignores this complexity and divides the total amount of selected products into the total amount of direct carbon emissions. It does not include all products produced. Furthermore, it treats all of the products included equally despite differences in their emissions profiles. If ARB insists on a product-based approach, we would support adoption of the EU factors for the Complexity Weighted Tonne benchmark in the first compliance period. While this concept does not have industry consensus and is not ideal for California, this benchmark is technically sound, rewards early action, and is neutral on configuration so that it does not punish California's refineries. (CHEVRON3)

Comment: In the draft Regulation, free allowances are allocated to facilities according to a benchmark set at a desired standard of performance. The benchmark is set at 90 percent of the sector's average emissions (tons CO_2) per barrel of product. This approach is referred to as "Simple Barrels." Unfortunately, the effect of this approach is to penalize refineries that have invested to meet California product specifications and other "clean fuel" mandates. ExxonMobil believes that the Simple Barrels approach is inappropriate as a benchmark for refining, given the vast differences in refining complexity across the sector. ExxonMobil has spent years optimizing its operations and equipment in order to both meet product demand in California and maximize energy efficiency. The Simple Barrels approach does not recognize the differences in refinery complexity and therefore, does not appropriately measure performance across all refineries. Moreover, the benchmark favors simple refinery configurations. The result is a benchmark that rewards a facility according to the amount of equipment it contains rather than according to the efficiency with which it operates that equipment. The Simple Barrels approach may lead to unintended consequences. The Energy Efficiency Based Allowance Distribution Methodology proposed by the Western States Petroleum Association (WSPA) for the first compliance period addresses these issues. The Energy Efficiency Based Allowance Distribution Methodology, or a similar approach, would recognize differences in complexity among refineries and enable distribution of allowances according to efficiency. Complexity-based approaches have been recognized by both industry and government organizations as appropriate for measuring performance in the refining sector. We believe complexity-based metrics are suitable for use in the California Cap and Trade program and would be more effective than the Simple Barrels approach for allocation. (EXXONMOBIL)

Comment: The simple barrel method should not be chosen as the benchmark methodology as it penalizes complex refineries. For instance, simple bbls favors refineries without hydrogen plants that purchase merchant hydrogen and penalizes refineries that have their own hydrogen plant. Refineries with cogeneration units that produce excess electricity are also penalized over refineries that do not have cogeneration units. The simple barrel method does not reflect the energy efficiency of a refinery—just the amount of energy it uses, and allocating allowances in this manner can have unintended consequences. If ARB does not select the WSPA proposed EII method then it should adopt grandfathering as it will treat refiners more equitably by not picking winners and losers. We highly recommend that CARB reexamine the basis for refinery allocation. (VALERO2)

Comment: Delete the simple barrel methodology refinery benchmarking methodology and replace it, beginning in the first period, with a benchmarking methodology that recognizes complexity of refineries such as the Ell-based methodology proposed by WSPA. The proposed simple barrel benchmarking methodology for refineries is an over simplification that does not accurately reflect the carbon efficiency of a refinery and should not be used, even as an interim solution. The simple barrel methodology should not be used to allocate free allowances for refineries. First, the simple barrel methodology is not accurate. It does not accurately represent the carbon intensity of all products produced by a refinery. Refineries vary significantly in the types of teed (crude and intermediate inputs) to the refinery, the finished and intermediate products produced, the on-site consumed products produced and the process units used to produce the products. Some refineries are designed to produce more transportation fuel products from heavier crude than others, thus deriving full advantage from our oil resources. Some refineries are designed produce intermediate products that require further processing at another facility. Some refineries produce products that are used internally for the refinery operations such as electric power, steam, hydrogen and low BTU gas (Flexigas), while other refineries purchase these products from third parties.

The proposed simple barrel methodology is too simple and does not account for all these differences. It does not accurately represent the carbon intensity or energy efficiency of a refinery. Second, the simple barrel methodology incentivizes results that are contrary to the objectives for providing free allowances. It encourages leakage and does not provide a transition period. The objectives of providing free allowances to industry are 1) to minimize leakage and 2) to provide adequate transition period to prevent unnecessary economic disruptions or short term costs. The proposed simple barrel methodology is contrary to these objectives. The use of the simple barrel methodology will result in a wide range of differences in percentage of tree allowances allocated to a refinery relative to the refinery's emissions. During the first compliance period in which the average industry sector reduction is approximately 4 percent, some facilities will receive only partial free allowances and must either reduce emissions or purchase compliance instruments in amounts equivalent to 5 to 10 times greater than the average sector reduction of 4 percent. At the same time other refiners will face no emission reduction or are given excess allowances to sell. Rather than providing a smooth transition period, this methodology would create disparate conditions that spur abrupt changes for some facilities and could add pressures that encourage leakage. Additionally, because the simple barrel methodology advantages simple refiners and the use of light crude, it could incentivize leakage with importing of more tight crude into California while exporting California domestic crude. This could also have the negative side effect of increasing the overall cost to produce clean products. In some cases, it may cause California refiners to reduce rates and/or import more products. Some argue that leakage would not occur by the use of simple barrel methodology as an interim method for the first compliance period because two years is insufficient time to make changes. During this interim period or period of uncertainty, refiners may delay investment decisions in California or alternatively divert capital investment to their portfolio outside of California. While it takes refiners four to five years to permit and execute large capital projects, refiners can make crude and product import and export and throughput decisions in a relatively short period of time. Third, it is not an effective template for others interested in Cap and Trade to follow. The simple barrel approach is a technically flawed methodology that results in large disproportionate allocations that could spur abrupt changes for some facilities. It does not provide for sufficient transition period to reduce industry emissions in a cost effective manner, nor is it consistent with the European Union. It also provides windfall profits to simple refiners, and is inconsistent with ARB's stated objectives. Given these significant shortcomings, CARB has not created a Cap and Trade model that will likely to be followed by others. Fourth, it does not encourage investment in California. Refiners have made investments to meet the California's clean fuel standards while continuing to meet California's transportation fuel needs. Many of these investments increased complexity of these refineries and are necessary to keep California's refineries competitive with refineries in other states as well as across the globe. The simple barrel methodology disadvantages complex refineries and penalizes these past investments. The lack of certainty in the rulemaking effort thus far continues to jeopardize industry investment decisions that are being made today, but won't be completed for five or 10 years. It does not encourage future investments to modernize and improve California's energy infrastructure and could cause discretionary capital investment to be moved to other states or regions of the globe in which the petroleum markets are growing or where more regulatory certainty is provided. Therefore, Shell recommends that the simple barrel methodology for refineries be deleted and beginning with the first period, use a benchmarking methodology that recognizes complexity of refineries, such as the EII based methodology proposed by WSPA. (SHELLOIL)

Comment: AB 32 gave ARB the authority to issue free allowances in an equitable manner that maximizes the total benefits to California and encourages early action to reduce greenhouse emissions. ARB has chosen to use output based benchmarks as one of the factors in granting free allocation to qualified facilities. Within the various industrial sectors, ARB has estimated that entity emissions range from less than 25 percent to about 500 percent of the benchmarks. Incentives for California entities to reduce emissions by a factor of 4 or 5 are not "correct," but are simply discriminatory given that California is among the states with the lowest carbon footprint in the nation. Tesoro has expressed its views and results of its studies regarding refinery benchmarking with ARB on several occasions. Three essential points have been discussed. First, consistent with commitment from ARB management, the benchmark method must recognize the emission reductions from early actions such as the Coker modification project at Tesoro's Golden Eagle Refinery. Second, that refinery benchmarking should not be subjective. Subjective measures of refinery activity such as crude throughput, product output, clean product output, refinery activity, refinery energy intensity, refinery carbon intensity or volume and quality of feedstock's and products may appear as logical choices as a basis for a benchmark but can easily favor some and discriminate against others. Third, use of any of subjective benchmarks exaggerates the difference between refineries by a factor 3 to 5 relative to any practical opportunity to reduce emissions. For these reasons Tesoro favors a benchmark that strongly considers baseline emissions for each refinery. The WSPA proposal considers baseline emissions, energy efficiency, and reduces the disparity within the sector while meeting ARB's primary objective of setting a correct incentive for the initial period and allows the program to start with minimal interruptions. (TESORO2)

Comment: For downstream (refining and related operations), WSPA believes that the simple barrel methodology clearly works against ARB's objectives to minimize leakage and a smooth start to the program. It is clear that the simple barrel method is simply inadequate and not a suitable benchmark for use in California because it:

- does not consider all the various products produced by a refinery
- applies a one-size fits all methodology for non-comparable sources
- fails to distinguish between facilities that produce their own on-site generated and consumed products such hydrogen, power, steam, flexigas or fuel gas
- rewards a facility based on the number and type of equipment it operates rather than the efficiency with which it operates that equipment
- does not reflect nor reward early actions to reduce energy consumption or improve operational efficiency

- is neither accurate nor representative of industry operations nor reflective of either energy or carbon conservation

In summary, use of the simple barrel method could lead to an inequitable distribution of allowances and disruption in the allowance trading market. In view of the shortcomings of the Simple Barrel Method and the strengths of the EII method, ARB should adopt the Adjusted EII methodology for refineries in the first compliance period as we work toward a complex-weighted barrel methodology. WSPA recommends that ARB use an Adjusted EII benchmark for refineries within the State. (WSPA3)

Comment: Section 95802(a)(202) defines Primary Refinery Products as aviation gasoline, motor gasoline, jet fuel, distillate fuel oil, renewable liquid fuels and asphalt. For each refinery, ARB will convert blendstocks into finished fuel, by using a blending ratio. WSPA has concerns with this definition as it excludes many refinery products such as LPG, Petroleum Coke, No. 6 fuels among many others, plus it does not take into account products consumed onsite such as hydrogen, power, steam or flexigas. Further, it is not clear or transparent as to how the blending ratio is derived and how it will be used to develop the final facility product total. As used in Appendix B, the primary product is used for benchmarking purposes in the Simple Barrel methodology. It is not clear, how ARB will manage the seasonal and annual changes in product volumes in the benchmarking calculations. WSPA opposes the simple Barrels benchmarking methodology for many reasons, including the fact that the Primary Produce definition is flawed and not transparent. WSPA recommends that the Adjusted EII methodology be adopted in lieu of Simple Barrel approach that will obviate the need for this flawed "primary produce" definition. (WSPA3)

Comment: WSPA's understanding of the primary objectives for allocating free allowances to trade exposed sectors are 1) to minimize leakage and 2) to provide transition assistance. The selection of the benchmark methodology can have significant impact on whether the program successfully works to support these objectives or, instead, frustrates progress toward a workable system to implement AB 32. WSPA supports the use of a well-designed benchmarking method that results in an equitable distribution of allocations. We agree with the ARB's statement in Appendix of the proposed Regulation that "benchmarks are metrics that enable the comparison of GHG performance across similar industrial facilities" and that benchmarks can be used as a basis for allocation in a market-based system such as Cap and Trade. Characteristics of a well-designed benchmark include:

- Accurate and reliable reflection of a facility's energy (and carbon) efficiency
- Direct relationship to GHG emissions
- Appropriate application to affected comparable facilities
- Clarity and transparency in calculating methodology
- Consistent with the objective of minimizing leakage and providing assistance during a transition period
- Equitable treatment of facilities irrespective of location (i.e., on-site or off-site)

- Does not award windfalls

Using these criteria, it is clear that changes proposed in the July 25, 2011 version of the Cap and Trade Regulation for both the refining sector and the oil and gas production sectors need to be revisited. WSPA recommends that ARB incorporate the GHG emissions from net power and heat used to produce the product into any product based benchmarks for upstream and refining and for all sectors. (WSPA3)

Comment: CARB should adopt the proposed WSPA methodology. This methodology accomplishes CARB's goals of incentivizing greenhouse gas emission reductions, improvements in energy efficiency, and rewarding early action. Output-based benchmarking may be appropriate for other sectors but would be a gross mistake for the refining sector. CARB's proposal for a "Simple Barrel" output-based benchmark for our industry would create large inequities between companies unrelated to greenhouse gas emissions and could result in unintended consequences that are contrary to AB32 goals. For example, this could reward the processing of certain crude oils in other States or countries and the importing of those intermediates to California for further refining. This does nothing to meet the goals of AB32 and could actually increase global emissions of greenhouse gases. (CONOCO2)

Comment: The Regulation contemplates use of a "simple barrel" methodology for the refining sector. If such a methodology is employed by CARB, we ask that CARB incorporate three key concepts. First, indirect emissions must be accounted for in the benchmark. If the Simple Barrel benchmark is going to be employed on an equal basis, then all emissions related to the output should be included in the benchmark. Indirect emissions from purchased electricity, purchased steam, and purchased hydrogen must be included. Emissions associated with sold electricity and sold steam should be excluded. Failure to properly account for emissions from purchased electricity penalizes refineries with cogeneration units, creates an unfair playing field between refineries, and creates perverse incentives for facilities to simply shift emissions by buying electricity and hydrogen rather than producing it. Second, baseline years should extend beyond 2008-2009. Limiting the baseline years to 2008-2009 fails to account for energy efficiency activities in earlier years. Furthermore, 2008-2009 could be years that are not representative of emissions or production for reasons such as having a refinery shut-down for maintenance (typically every five years). We recommend expanding baseline years to 2006-2010. Third, other factors could influence a Simple Barrel benchmark and should be considered (i.e., step-changes) for later compliance periods. This additional review is necessary regardless of whether the later compliance periods use the Simple Barrel methodology or a methodology that is complexity or efficiency based. (BP2)

> **Response:** We allocate free allowances to the industrial sector for two purposes: (1) to provide transition assistance, and (2) to prevent leakage. Transition assistance allows industrial sectors at the outset of the program to avoid sudden or undue short-term economic impacts, flexibility to comply, and incentives to innovate to a low-carbon economy. We believe our product-based

benchmarking methodology is appropriate and will encourage energy efficiency. In a market-based program such as cap-and-trade, the goal of benchmarking is not to set an allowable level of emissions form each facility. Rather, the benchmark is used as one factor to allocate free allowances to assist facilities for the cost of compliance to prevent leakage and to incentivize them to reduce GHG emissions.

After reviewing comments received during the 45-day comment period for the regulation, numerous consultations with stakeholders, and analysis of additional data, we modified our approach for allowance allocation to the refinery sector in the second 15-day changes to the regulation. The new approach includes the "tempering" requested by stakeholders to address transition risk. In the second compliance period, we employ the CO_2 weighted tonne (CWT) approach which is a throughput-based benchmark that reflects refinery complexity. The following is a detailed summary of the changes we made.

In section 95891(d), we added a new methodology for allocating to individual operators in the petroleum refining sector in the first compliance period, in response to stakeholder comments about the impact of the prior proposal on equity in the refining sector in the first compliance period. Under the new text, complex refiners' allowances are allocated based on a methodology initially proposed by the Western States Petroleum Association. This approach allocates allowances based on the following factors: (1) historical emissions from for each refinery, (2) the Solomon Energy Intensity Index (EII) for each refinery, (3) an adjustment factor to reduce competitiveness impacts of allowance allocation between in-state refineries, and (4) future emissions for each refinery. The Solomon EII is a complexity-adjusted measurement of refinery energy efficiency developed by Solomon Associates. Solomon Associates has been developing energy-efficiency benchmarking for energy-intensive industries for the past 29 years. They maintain an extensive database for refineries' energy consumption and process data covering over 70 percent of global refining capacity. We believe that the EII is the most appropriate performance metric for complex facilities in the first compliance period. This metric is well understood by all complex facilities and has been recognized under the U.S. EPA's ENERGY STAR Program. Appendix A of the Second 15-Day Change Notice details the approach and analysis of the modified refinery allocation.

Simple refineries that do not have an EII value, or those without a representative EII value as determined by the Executive Officer, are allocated to using the "simple barrel" product benchmark proposed in the first 15-day changes to the regulation. We updated the value for this simple benchmark from 0.0465 allowances/barrel of primary refinery products to 0.0462 allowances/barrel. We made this change to reflect additional data that was provided by covered refineries and the inclusion of 2010 data in the development of the benchmark. We imposed a limit on the amount of allowances a facility can receive based on historical emission levels consistent with stakeholder comments. This approach will prevent any excessive rewards due to free allocation under the simple barrel metric.

For the second and subsequent compliance periods, we will allocate allowances to all refiners using the “Carbon Dioxide Weighted Tonne” (CWT) approach. This metric is based on the refinery benchmarking conducted for the European Union’s Emissions Trading Scheme.

We recognize the importance of indirect carbon costs. We include adjustments for purchased heat and for heat and power sold in the refining benchmarking. We believe it is premature to add an adjustment for power purchased at this time. This is because purchased power may not create an indirect carbon cost in all cases. It is ARB’s goal to see a carbon price properly embedded in all purchased power, including utility rates. If and when this occurs, the compensation for these indirect carbon costs could be incorporated into the product benchmarks (or reductions in these costs created in some other fashion) as necessary, to help minimize leakage. We will revisit this issue once the CPUC proceeding addressing utility costs and revenue issues associated with greenhouse gas emissions concludes. We recognize the issues associated with imported hydrogen. We believe the CWT allocation approach properly addresses these issues.

For the refining sector, we have the most confidence in emissions data reported to ARB under the mandatory reporting program, beginning with the 2008 data year. On a case-by-case basis we will consider high-quality data from earlier years for establishing baseline emission levels for allocation purposes. We agree that it is necessary to continue to review the allowance allocation to refineries as part of ongoing program review.

Oppose EII, Support Simple Barrel

C-70. Comment: WIRA supports the use of the Product Output-Based Allocation Calculation Methodology and the calculation modifications as described in section 95891(b). WIRA also supports the selection of the Simple Barrel Benchmarking approach contained in Table 9, 1-Product Based Emissions Efficiency Benchmarks. No other approach to allocation distribution is as transparent and predictable, nor is any other approach as consistent with the stated regulatory goal of focusing on output of products from regulated facilities. (WIRA3)

Response: Simple refineries that do not have an EII value, or those without a representative EII value as determined by the Executive Officer, are allocated to using the “simple barrel” product benchmark proposed in the first 15-day changes to the regulation. We updated the value for this simple benchmark from 0.0465 allowances/barrel of primary refinery products to 0.0462 allowances/barrel. We made this change to reflect additional data provided by covered refineries and the inclusion of 2010 data in the development of the benchmark. We imposed a limit on the amount of allowances a facility can receive based on historical emission levels consistent with stakeholder comments. This approach will prevent any excessive rewards due to free allocation under the simple barrel metric.

C-71. Comment: WIRA supports the use of the Simple Barrel approach for direct allocation of allowances described in Subarticle 9. However, the Modifications, as proposed, do not recognize an important product produced by WIRA members that should be considered a Primary Refinery Product—Residual Fuel Oil. (WIRA3)

Response: We do not currently believe that residual fuel oil represents a primary refinery product that is in need of free allocation to prevent leakage risk. However, beginning with the 2011 data year, we will collect detailed, third-party verified, refinery product data as part of the effort to monitor for emissions leakage in this sector. We will monitor the production of residual fuel oil in the state using this data set and consider changes to free allocation as needed to address leakage issues.

Oppose EII, Support Simple Barrel if Stringency Is Increased

C-72. (multiple comments)
Comment: Output-based refinery benchmarks should be set based on "best in class" emission rates, similar to the EU approach. We recommend a benchmark of 0.037 metric tons of allowances per barrel of output, approximately 20 percent lower than the proposed benchmark of 0.0465 metric tons of allowances per barrel. The ICCT recommended value is comparable to national average refinery emissions times 90 percent. This value is met or exceeded by several California refineries while the remainder would be required to purchase allowances as shown in CARB's Appendix B to the recent Cap and Trade Regulation revisions. An alternative approach, is a benchmark of approximately 0.03 metric tons of allowances per barrel based on California best in class refineries. EU refinery emissions are 0.0304-0.0306 metric tons per barrel throughput. The EU ETS reduced the GHG benchmarks by an additional 15-20 percent from average EU refinery emissions. While the EU reported per barrel throughput does not directly correspond to CARB's list of "Primary Refinery Product," a California benchmark of 0.030 allowances per barrel of "Primary Refinery Production" will provide at least as many, if not more, allowance per barrel than EU refineries receive. (ICCT3)

Comment: We oppose the WSPA proposal that mixes grandfathering, increased free allowances for refineries that increase their GHG emissions, and a very weak energy efficiency incentive. Grandfathering rewards the use of high-emitting processes and inputs. In addition, the WSPA proposal that CARB give a refinery free GHG allowances to offset most of allowances needed for emission increases would directly contravene the potential benefit of a Cap and Trade system. Facilities that choose to increase use of heavy Venezuelan crude, for instance, would receive free allowances to largely offset their increased GHG allowance obligation (while also increasing criteria pollutant emissions). Facilities that source more lower carbon crude, improve coking operations, implement renewable energy or carbon capture projects would lose most of the benefit of lower GHG compliance obligations due to cuts in their GHG allocations under the WSPA proposal. This proposal would run contrary to CARB's laudable efforts to encourage low carbon fuels and promote economic incentives for GHG emission reductions. Free GHG allowance allocations to incumbent high carbon industries are a potential barrier to advanced technology. (ICCT3)

Comment: Any free allowances given to refineries should be tied to emission reduction strategies such as advanced technology and energy efficiency. As a second choice, we believe that CARB's output-based refinery allocation proposal is superior to grandfathering. (ICCT3)

Comment: The WSPA proposal to use the Solomon EII index to rank the refineries' GHG performance is flawed since the proposed ranking is based on energy rather than carbon efficiency. This can encourage use of high carbon feedstocks which would undermine the carbon reduction objectives of AB 32. In addition this index is an industry sponsored and funded benchmarking service which is proprietary. The rankings lack public accountability since the proprietary methodology is non-transparent and based on confidential information. The WSPA allocation proposal is not based on California production and so does not maximize production in California. Finally the proposal dilutes incentives for carbon reductions by compressing the range of the distribution of allowances. In effect poor performers are not 'penalized' too much and will obtain significant subsidies to continue carbon intensive production. This payment for poor performance will dilute the incentives for improving performance. Do not use the WSPA proposed Solomon EII index as the refinery GHG performance benchmark. (KUSTIN13, UCS7)

Comment: For the refining sector, CARB has proposed an output based benchmark of 0.0465 allowances per barrel of primary product. The rationale for this proposal is that it is 90 percent of the value of the average emissions per unit of primary product among California refineries. The supposition is that this percentage reflects a 'best practice' assessment of carbon intensity performance in the refining sector. Under this proposal, nearly half (7/15) of refineries lie below the proposed benchmark, indicating that almost 50 percent of refineries will have surplus allowances to sell. This windfall occurs as a direct result of the proposed weak benchmark standards. The proposal, if adopted, would be a missed opportunity to promote refinery best practices and compares poorly with the EU ETS performance benchmarks in which only the top 10 percent of refineries are deemed 'good' performers and get all their allowances for free. (KUSTIN13)

Comment: Many of the benchmarks proposed are based on the historical GHG intensity performance of California producers. In some cases these data restrictions result in weaker performance benchmarks. California refineries have emissions intensities that are around 30 percent higher than the East Coast and the Midwest. Calculations show that if the CARB methodology was used with national rather than California data, the refinery GHG benchmarks would be around twenty percent lower (approximately 0.0385 allowances per primary product), rather than the CARB proposed value of 0.0465 allowances per primary product. We recommend that the refinery emission intensity benchmark should be based on best-in-class performers at the national rather than the California level. (KUSTIN13, UCS7)

Response: Simple refineries that do not have an EII value, or those without a representative EII value as determined by the Executive Officer, are allocated to using the "simple barrel" product benchmark proposed in the first 15-day changes to the regulation. The value for this simple benchmark was updated from 0.0465 allowances/barrel of primary refinery products to 0.0462 allowances/barrel. We made this change to reflect additional data provided by covered refineries and the inclusion of 2010 data in the development of the benchmark. We imposed a limit on the amount of allowances a facility can receive based on historical emission levels consistent with stakeholder comments. This approach will prevent any excessive rewards due to free allocation under the simple barrel metric.

Complex refiners' allowances are allocated based on a methodology initially proposed by the Western States Petroleum Association. This approach allocates allowances based on the following factors: (1) historical emissions from for each refinery, (2) the Solomon Energy Intensity Index (EII) for each refinery, (3) an adjustment factor to reduce competitiveness impacts of allowance allocation between in-state refineries, and (4) future emissions for each refinery. The Solomon EII is a complexity-adjusted measurement of refinery energy efficiency developed by Solomon Associates. Solomon Associates has been developing energy-efficiency benchmarking for energy-intensive industries for the past 29 years. They maintain an extensive database for refineries' energy consumption and process data covering over 70 percent of global refining capacity. We believe that the EII is the most appropriate performance metric for complex facilities in the first compliance period, despite the fact that it is based on energy efficiency and not greenhouse gas efficiency. This metric is well understood by all complex facilities and has been recognized under the U.S. EPA's ENERGY STAR Program. EII values reported by each facility will be independently verified by third-party verifiers and through our consultation with Solomon Associates.

For the second and subsequent compliance periods, we will allocate to all refiners using the "Carbon Dioxide Weighted Tonne" approach. This metric is based on the refinery benchmarking conducted for the European Union's Emissions Trading Scheme.

We do not agree that our approach creates an incentive to switch to lower quality sources of crude. We believe that the allocation stringency correctly provides all facilities with the correct incentives to make greenhouse gas reductions. We do not agree that our approach supports poor performance. We agree that it is necessary to continue to review the allowance allocation to refineries as part of ongoing program review. We will consider national data in the context of benchmark stringency as a robust national data set is developed by the U.S. EPA's greenhouse gas reporting program.

Appendix A of the Second 15-Day Change Notice details the approach and analysis of the modified refinery allocation.

Oppose EII and Oppose Simple Barrel

C-73. (multiple comments)
Comment: ARB's proposed performance benchmarks support poor performance. Relevant available data and evidence that ARB ignores indicate that average California refinery emissions intensity is at the extreme-high end of the range among U.S. refining regions, exceeding that of any other region by a wide margin. ARB-reported emissions from all major California refineries exceed average Midwest and East Coast emissions and seven major California refineries exceed average Gulf Coast refinery emissions. Refinery emissions performance across the rest of the U.S. demonstrates what refineries can achieve under the right conditions. ARB's analysis commits a serious error by ignoring this evidence that a large refinery emission reduction is available. ARB's proposal sets the benchmark at 90 percent of the California statewide average. Based on publicly verifiable evidence this would set the benchmark at the equivalent of 346 kg/m^3 crude refined. Average 2003–2008 performance in every other major U.S. refining region is below (better than) 346 kg/m^3. ARB's proposed benchmark would inappropriately sanction and support excess emissions and poor performance by California refineries. (CBE2)

Comment: ARB's proposed benchmark fails to measure performance accurately. Peer reviewed evidence that ARB ignores shows that refinery energy and emissions intensities are not significantly associated with refinery products yield. Other factors such as market conditions cause products yield to vary independently from refinery emissions to some extent. Therefore, products yield is an unstable and unreliable metric for benchmarking refinery emissions intensity. ARB's rationale for its benchmark ignores these facts. CBE's analysis of national and California refinery operating data shows that average observed 2004–2009 California refinery emissions differ from those expected based on ARB's "primary products" benchmark by 38 percent and differ from those expected based on ARB's benchmark even when asphalt is excluded by 22 percent. ARB's proposal to measure emissions intensity as mass emitted/volume product output is substantially less accurate and reliable than measuring emissions intensity as mass emitted/volume crude refined. ARB's proposed benchmark would fail to measure refinery emissions performance accurately. (CBE2)

Comment: ARB proposes a refinery GHG emissions performance benchmark (section 95891 Table 9-1) that is based on five assumptions, none of which is supported by publicly or scientifically verifiable data or evidence. First, ARB assumes that refiners' emissions reports pursuant to ARB's Mandatory GHG Reporting Rule (MRR) are accurate. The sum total of these polluter-reported emissions is quantitatively different from the statewide emissions based on publicly reported, openly verifiable statewide refinery fuels consumption data and emission factors developed and used by the Energy Information Administration for reporting U.S. emissions under international treaties. The reason for the discrepancy cannot be verified publicly because, despite the proffered excuse that MRR emissions are certified by "independent" contractors hired by the oil companies, both the emissions data and the certification details are kept secret from the public as a matter of ARB policy. Second, available publicly verifiable evidence indicates that ARB's "primary products" metric is not an appropriate metric for benchmarking refinery emissions intensity and ARB provides no data or analysis specifically supporting its assumption to the contrary. Third, ARB assumes that benchmarking individual refineries' emissions against products output data that are kept secret from the public will be accurate and appropriate. Available publicly verifiable data and analysis indicate that it is not accurate, and ARB's use of secret products data would make the extent of this error unverifiable by the open scientific method. Fourth, ARB assumes that the average based on its secret products data, its secret emissions data, and facility identities it keeps secret (presumably to keep facility products data secret) represents refinery climate impact performance adequately. However, ARB's own chart presenting this average (Figure 3, Appendix B) indicates an uneven distribution of facility performance data that calls the representativeness of the average into question. Further, available publicly reported data show that fuels yield roughly tracks refinery crude capacity, and three of the four highest mass-emitting refineries emit less per barrel crude capacity than the average among California fuels refineries. Finally, ARB ignores refinery performance outside California, which is the majority of U.S. refinery performance data. ARB provides no scientific support for that omission, and does not even attempt to claim that California data alone adequately represent refinery performance. (CBE2)

Comment: ARB ignores a more accurate and reliable performance benchmark. CBE's published research shows that crude feed density, sulfur content, the ratio of light liquids to other refinery products, and capacity utilization explains differences in refinery emissions intensity across the major U.S. refining regions. Applying this metric to operating data from California refineries shows that observed average 2004–2009 statewide refinery emissions are within 1 percent of those this metric would benchmark. ARB says it is considering alternative refinery benchmarks. However, ARB has ignored this evidence, discussed no option to include crude feed quality, and admits that it has not collected California refinery crude feed quality data. ARB's admission that it did not collect any data on the density or sulfur content of crude feeds refined in California demonstrates that ARB could not have analyzed impacts of crude feed quality on refinery emissions in any part of its Cap and Trade scheme or its Low Carbon Fuel Standard. As a result of this broader failure of its analysis, ARB proposes an inaccurate refinery benchmark while ignoring a more accurate one. (CBE2)

Comment: ARB's inaccurate benchmark and inappropriate assistance factor would allow emissions to increase far above current already-high emission levels by failing to address the dominant refinery GHG emissions driver when that driver is changing quickly now. Crude feed quality is the dominant driver of changes in refinery emission intensity observed nationwide and in California. Statewide refinery crude supply is changing rapidly now such that up to three-quarters of the California refinery crude feed will most likely be from different or “new” sources by 2020. ARB’s proposal to sell refineries emission allowances that would allow increasing emissions for less than the profits they would make on the marginal savings from lower quality, higher-emission new sources of crude will strongly encourage them to switch to this “dirtier” feedstock. ARB’s inaccurate benchmark and proposal to delay even the need for refiners to buy cheap pollution allowances at a profit would guarantee this result. Based on the same data and methods that predict average observed 2004–2008 California refinery emissions within 1 percent, switching to the average heavy oil as defined by the U.S. Geological Survey for 70 percent of California refinery crude feed by 2020 would increase statewide refinery emissions by approximately 49 percent or 19,600,000 tonnes/year by 2020. Again, ARB admits it did not analyze this crude quality impact. Ongoing emissions in excess of those that could be achieved by 2020 if ARB’s flawed proposals are replaced by effective environmental protections would add another 7.8 million tonnes/year to the total emissions impact of ARB’s flawed proposals. (CBE2)

Comment: ARB’s refinery benchmark and assistance factor fail to achieve available emissions reductions. The long, terminal decline of California’s existing crude production sources that has continued since the mid-1980s, government analysis and industry analysis all project with confidence that some 70–76 percent of crude processed by California refineries in 2020 will not be from existing California production. Further, the ongoing decline of Alaska’s current production and the ease of decadal switching among foreign supplies demonstrated historically show that, for all practical purposes, up to three-quarters of the 2020 California crude feed will be from “new” sources. California refineries must select and adjust to new and different crude oils. Since California refineries must change the driving factor causing their extreme-high emission intensity, they can choose blends of “new” crude oils of better quality, like every other major U.S. refining region does, and that would curb their emissions. Replacing the 70 percent of refinery crude input that will be lost from current California production by 2020 with crude the quality of the total average East Coast refinery input could curb average California refinery emission intensity to approximately 308 kg/m3, a reduction of –20 percent or –7.8 million tonnes/year, as CO_2. This is based on the same data and methods that predicted currently observed California refinery emissions within 1 percent on average. However, ARB proposes to implement an inaccurate and unreliably benchmark and a flawed assistance factor that gives away for free the vast majority of allowances that refineries already can know they could buy later at a profit on cheaper, higher-carbon crude. Thus, ARB’s proposal will not achieve this reduction any more than it will prevent the emissions increase discussed above. Therefore, approximately 7.8 million tonnes/year of available emissions reductions and 19.6 million tonnes/year of avoidable emissions increases, for a refinery emissions excess above that which can be achieved in 2020 totaling 27.4 million tonnes/year, can be expected from ARB’s flawed proposals. (CBE2)

Response: We allocate free allowances to the industrial sector for two purposes: (1) to provide transition assistance, and (2) to prevent leakage. Transition assistance provides industrial sectors at the outset of the program to avoid sudden or undue short-term economic impacts, flexibility to comply, and incentives to innovate to a low-carbon economy. We believe our benchmarking methodology is appropriate and will encourage greenhouse gas efficiency in production of the primary refinery products that we identified. In a market-based program such as cap-and-trade, the goal of benchmarking is not to set an allowable level of emissions from each facility or to anticipate the emissions from each facility based on any set of correlated factors. Rather, the benchmark is used to allocate free allowances to assist facilities for the cost of compliance, to prevent leakage and to incentivize them to reduce GHG emissions and continue efficient in-state production.

We analyzed a wide variety of proposals for refinery benchmarking. Our approach is outlined in Appendix A to the second 15-day changes to the regulation. We create a first compliance period approach based on the simple barrel benchmark for the simple facilities and the Solomon EII approach for the complex facilities. For the second and subsequent compliance periods, we will allocate to all refiners using the “Carbon Dioxide Weighted Tonne” approach. This metric is based on the refinery benchmarking conducted for the European Union’s Emissions Trading Scheme.

We do not agree that our approach is inaccurate, that the assistance factor is inappropriate, or that our approach supports poor performance. We do not agree that our approach creates an incentive to switch to lower-quality sources of crude. We believe that complexity-adjusted allocation methods are neutral to crude quality. That is, they neither excessively penalize nor reward refineries sourcing poorer quality crude. We do not believe these methods create an incentive to switch to poorer quality crudes. The phase-out of free allocation and switch to auctioning as the primary method for allocation to the refining sector by the third compliance period will penalize facilities with more emission-intensive processing, including more emissions-intensive processing due to crude quality.

With respect to data use, we use an average of the three most current years of product output and emissions data in developing the simple barrel product benchmark. We have confidence in the accuracy of emissions data reported to us under the mandatory reporting program, beginning with the 2008 data year. We used product data reported voluntarily to ARB and compared this information to product data that is reported to the California Energy Commission (CEC) under the Petroleum Industry Information Reporting Act. This product information is made publicly available by the CEC at a statewide level of aggregation in the CEC’s *Weekly Fuels Watch Report*. On a case-by-case basis, we considered high-quality emissions data from earlier years for establishing baseline emission levels for allocation purposes. We agree that it is necessary to continue to review the allowance allocation to refineries as part of an ongoing program review.

Coke Calcining

C-74. Comment: CARB has established a benchmark for petroleum coke calcining that is noted as consistent with the Europe benchmark. This may or may not be appropriate for our specific calcining operation at our Contra Costa Carbon Plant. We will be in contact with CARB staff to understand the CARB basis and make recommendations for our operation as appropriate. (CONOCO2)

Response: Thank you for your participation in developing the coke calcining benchmark. We believe we selected an appropriate benchmark.

Soda Ash

C-75. Comment: Table 9-1 references NAICS Code 212391, Potash, Soda, and Borate Mineral Mining. This U.S. industry comprises establishment primarily engaged in developing the mine site, mining, and/or milling, or otherwise beneficiating (i.e. preparing) natural potassium, sodium, or boron compounds. Dry lake brine operations are included in this industry, as well as establishments engaged in producing the specified minerals from underground and open pit mines. To more accurately reflect the product mix for the compounds designated on the Code and for this type of operation in California, modify "Benchmark Units" as follows:

Allowances / Short Ton of Soda Ash Equivalent (Soda Ash, Biocarb, Borax, V-Bor, DECA, PYROBOR, Boric Acid, ~~and~~ Sodium Sulfate, Potassium Sulfate, Potassium Chloride and Sodium Chloride. (SVM2)

Response: This change in the benchmark units was inadvertently left out of final 15-day changes to the regulation, but will be incorporated when we make further changes to the regulation sometime next year. The units have been changed in the definition of "Soda Ash Equivalent" in the Mandatory Reporting Regulation, which is the basis for allocation, so the oversight will not affect the industry's allocation.

Steel

C-76. Comment: The Proposed Benchmark for Cold Rolled and Annealed Steel Sheet Production in Appendix B cites that "the ease of developing product-based benchmarks depends on the homogeneity of products within the benchmarked industrial sectors." The Appendix then goes on to list only one benchmark for Cold Rolled and Annealed Steel Sheet (CRS) Production. However, there are two types of annealing processes that result in different steel properties, which, in turn, result in two different CRS products. Steel can be annealed using either a batch annealing (BA) process or a continuous annealing (CA) process, and "BA" or "CA" is typically part of the CRS product description. Batch annealing is a multi-day process where up to several dozen coils are stacked in a furnace, and heated until the correct properties are obtained. In a continuous annealing process, the steel is uncoiled and passes in loops through a furnace for several minutes heating a cross section of the strip for several minutes. Continuous annealed material has a fine grain structure and is more resilient than batch annealed material which has a coarse grain structure and excellent formability. It is not a product that is simply differentiated by technology. Each process creates a unique product and therefore, each process should have its own benchmark. (UPI)

> **Response:** We investigated the difference between BA and CA to understand the implication to the benchmark. Because of the difference in process (BA uses lower temperature and longer time; whereas, CA uses higher temperature and a much shorter time), CRS from BA and CA could have different characteristics in terms of formability and so on. However, since the products can be used for the same end-use for most applications, we concluded that CRS can be grouped, regardless of technology.

C-77. Comment: The benchmark for Tin Steel Plate Production is listed as 0.0197 on page 10 of the Appendix. UPI is the only company that produces this product, and through communication with Mihoyo Fuji of the Air Resources Board, we came to the conclusion that our emission intensity for this product to be 0.03536. The Appendix states that the "staff selected a benchmark based on the "best-in-class" value (i.e., the emissions intensity of the most GHG-efficient California facility)." Since UPI is the only California facility that produces this product, the benchmark should reflect our current emission intensity levels. (UPI)

> **Response:** We reviewed the number and concluded that two years' worth of emissions had been mistakenly removed from the numerator in the initial benchmark calculation. This error made the benchmark number significantly lower than intended. We corrected the error.

C-78. Comment: UPI currently runs an Acid Processor (AP) in concurrence with our Pickle Line Tandem Cold Line (PLTCM) which produces Pickled Steel Sheet Product. The AP uses natural gas to regenerate hydrochloric acid which is then returned to the pickle line. Because UPI is the only facility that recycles and regenerates our spent acid, the natural gas used should not be counted against our emission intensity benchmark for our Pickled Steel Sheet Product. (UPI)

> **Response:** After careful consideration, we decided not to include the acid processor emissions directly in development of the Pickled Steel Sheet product benchmark. Free allocation will be given to UPI based on energy benchmarking for this unit.

Leakage

Miscellaneous

C-79. Comment: CARB could provide clarity regarding the potential adjustment to all industrial assistance allocations described in section 95870(e)(3) by referencing this potential adjustment in section 95899(a) and section 95891(a). (APC2)

> **Response:** We believe that the description found in section 95870(e)(3) is sufficient.

C-80. (multiple comments)
Comment: We are concerned that CARB is overestimating the likelihood of leakage risk and this is resulting in the subsidization (via free allocations) of carbon intensive industries. There are also significant costs from the free allocation of valuable allowances since these public monies could instead be spent on lowering the costs of the Cap and Trade program. Leakage risk analysis should be re-evaluated before the second compliance period to take into account transportation costs and the ability of non-Californian companies to compete with California producers. (KUSTIN13)

Comment: UCS is concerned that CARB is overestimating the likelihood of leakage and that this is resulting in the subsidization (via free allocations) of carbon intensive industries, such as refineries. As discussed, there are significant costs from the free allocation of valuable allowances since these public monies could instead be spent on lowering the costs of the cap-and-trade program. A reassessment of leakage risk should be undertaken which takes into account transportation costs and the ability of non-Californian companies to compete with California producers. Leakage risk analysis should be re-evaluated before the start of the second compliance period. (UCS7)

Comment: The proposed level of allocation to the industrial sector is much higher than is needed to combat leakage. Your own Economic and Allocations Advisory Committee found that the need for free allowances to address leakage is small. The biggest recipients of these free allowances in the staff proposal are the oil extraction and refining industries, which actually have a low susceptibility to leakage. We ask you to re-classify petroleum extraction and refining as low leakage risks, and to reduce their free allocations accordingly. (SIERRACLUBCA5)

> **Response:** We believe that free allocation to some industrial sources is a desirable means of minimizing leakage and providing transition assistance to existing California businesses. Transition assistance is designed to ensure that these businesses will not incur significant financial impacts in the beginning of the program, and to provide them with a reasonable planning horizon to begin making cost-effective emissions reductions. After the first compliance period, transition assistance will be phased out, and the level of free allocation to all but the most trade-exposed industrial sources will decline. Before the start of the second compliance period, we will evaluate the need for free allocation for the

prevention of emissions leakage, paying special attention as new information that could improve the technical accuracy of the assessment becomes available.

C-81. (multiple comments)
Comment: It is premature to make a determination of leakage risk less than 100 percent for any industrial sector past the first compliance period. The leakage analysis is insufficient to justify this. There is adequate time to do a leakage risk analysis prior to the 2015 compliance time period. The analysis should include the level of participation by other states and jurisdictions in the program as a key metric for how much each industry sector is at risk for leakage. CMTA reaffirms the comments on this topic made to CARB on December 9, 2010. There is not substantial evidence in the record to justify the leakage categorization less than 100 percent for any industrial sector. (CMTA3)

Comment: The leakage analysis is insufficient to justify less than 100 percent allowance allocation to the industrial sector in future compliance periods. It is also premature to make this decision. There is time to do such analysis prior to the 2015 compliance time period. This decision should depend on the level of participation by other states and jurisdictions in the program as a key metric for how much each industry sector is at risk for leakage. (CALFP3, AB32IG3)

Comment: The Industrial Environmental Association (IEA) continues to believe that the methodology and calculations to establish leakage categories need further review and refinement. The categories do not accurately reflect or attempt to measure how highly sought after some of these businesses are by other states and countries, with offers of financial incentives, fast-track permitting and less regulation. Industries, such as pharmaceuticals, aeronautics and specialty manufacturing are all at high risk to leave the state and should be treated accordingly in the leakage classifications. (INDENVASSOC2)

Response: We believe that the assessment methodology and framework we established is the best available technique that can be applied to all covered sectors, uniformly using publically available information. We believe that it is essential that carbon pricing is applied broadly to ensure that cost-effective emissions reductions are achieved. To this end, it was critical to classify sectors in different leakage risk categories (high, medium, and low) to minimize leakage from relatively high-risk industries while avoiding undue distortions to carbon pricing caused by overcompensating relatively low-risk industries. That said, we will monitor economic impacts to covered sectors, and will evaluate the leakage assessment methodology before the start of the second compliance period; paying special attention as new information becomes available that could improve the technical accuracy of the assessment.

C-82. Comment: The Regulation seems to conclude through use of a very simplistic analysis, that industry can be subjected to a significant level of additional cost and trade exposure before leakage will occur. When a sector operates in a global market, against global competition, where the prices are set by global supply and demand, the only way to fully mitigate trade exposure (short of a global GHG policy) is through 100 percent free allocation. Any less free allocation exposes California industry to incremental costs to which their competitors (both international and other states) are not exposed. It is really a matter of how much trade exposure and how much leakage of jobs and emissions California policymakers are willing to accept and impose on California industry. The trade exposure of the refining industry is well documented. Until a critical mass of states and countries adopt carbon policy that results in a similar cost of carbon, California should freely allocate 100 percent of allowances to trade-exposed industry. Further, the Regulation must contain a commitment and process to evaluate the continuing extent of trade exposure of California industry subject to the Cap and Trade Regulation. A clear commitment to and process outlining a periodic review of the Cap and Trade language could serve this purpose. (BP2)

> **Response:** As is demonstrated in Appendix K of the Staff Report, the trade exposure of the refining industry, using the ratio of imports and exports relative to domestic market size, was medium. We used the best available information and analysis tools, incorporating methods from other programs such as the EU ETS, the proposed Australian program, and the analysis from the Waxman-Markey bill, to complete our leakage risk analysis. That said, we will monitor economic impacts to covered sectors and evaluate the leakage assessment methodology before the start of the second compliance period, paying special attention as new information becomes available that could improve the technical accuracy of the assessment.

C-83. Comment: CCEEB recommends that ARB establish a test to determine if an industry is trade exposed. The ARB's trade exposure test should rely on two criteria: (1) is there a federal program; and (2) is there linkage to broad markets (i.e., larger or equal to the California market)? Allocations should be evaluated every three years in relation to the trade exposure test and other market indicators, such as the repots and recommendations by an independent market monitoring committee. (CCEEB3)

> **Response:** These comments fall outside the scope of the First 15-Day Change Notice. While no further response is required, we want to assure the commenters that we will provide a level of transition assistance designed to ensure that California businesses will not incur significant financial impacts in the beginning of the program, and to provide them with a reasonable planning horizon to begin making cost-effective emissions reductions.
>
> As noted in the Staff Report, we are committed to monitoring how covered sectors, especially those who receive free allocation, address carbon costs once the program is in place. But until the program is in place, we will not have the data to substantiate or negate the concerns raised.
>
> Per Board Resolutions 10-42 and 11-32, we will continue to review information concerning the emissions intensity and trade exposure of different industries in

California. We will recommend changes to the Board on leakage risk determinations, if needed, prior to the allocation of allowances for the second compliance period starting in 2015 for industries identified in Table 8-1 of the cap-and-trade regulation. We will update the Board annually on the status of the cap-and-trade program, including, to the extent feasible, information on shifts in business activity that may result in emissions leakage and changes in market share for covered entities and sectors.

C-84. Comment: We understand that ARB is continuing to review where industries are placed on Table 8-1. We intend to seek further dialogue with ARB regarding the appropriate placement of our industry, in accordance with the applicable criteria. (UNITEDAIRLINES2)

Response: We had further dialogue with the commenter and do not believe the placement of aircraft manufacturing support activities for air transportation in Table 8-1 warrants change at this time.

Cement/Lime/Gypsum

C-85. Comment: CARB recognized in its December 16, 2010, Resolution that the "cement sector is particularly well-suited as a pilot project for the development and consideration of a border adjustment measure." As a result, CARB directed its staff to consider a border adjustment for cement and to implement it if is feasible and necessary.

CARB's proposed "best-in-class" benchmark will, by design, impose immediate costs on California cement producers that will not be borne by cement producers outside of California. CSCME has provided evidence to CARB of the California cement industry's high vulnerability to leakage. This evidence includes the magnitude of GHG intensity of cement production, extremely limited cost-effective abatement opportunities, the fact that cement is a fungible commodity sold primarily on the basis of price, high fixed costs that incentivize maximizing capacity utilization, and exposure to unregulated competition. These incremental costs, along with the high leakage vulnerability of California cement producers, heighten the need for prompt implementation of a border adjustment measure to minimize leakage.

CARB has shown an understanding of the particular vulnerability of the cement sector to leakage, and this demonstrates the necessity of a border adjustment measure. Moreover, CSCME is prepared to assist CARB by providing data and analysis necessary to develop a border adjustment measure, ensuring that implementation of a border adjustment measure for cement is also feasible. (CSCME4)

Response: We classified cement as high-leakage risk and provided free allocation at a level we believe is sufficient to minimize this leakage risk. However, we believe that the cement sector is able to pass some of the cap-and-trade program costs to consumers. Therefore, we believe, at this point there is insufficient evidence to warrant implementing a border adjustment in addition to free allocation. Per Board Resolution 10-42, we will review the issues related to implementation of a border adjustment to impose obligations on importers of cement that are equivalent to those faced by California cement manufacturers under the cap-and-trade regulation, and to implement such a provision, if it is feasible and necessary, to avoid leakage in the cement sector. We will continue working, with input from stakeholders, on the possibility of implementing border adjustments for maximizing leakage protection.

C-86. Comment: The annual Industry Assistance Factor for the Gypsum Product Manufacturing (GPM) industry should be 100 percent for the entire period 2013 through 2020. It is our position that in assigning a "medium" leakage risk classification to the GPM industry, ARB has understated the risk leakage for the industry. In assigning a leakage risk classification to an industry, ARB applies a methodology that assigns equal weight to the concepts of emissions intensity and trade exposure. The GPM industry should not be evaluated as an "emissions intense" industry. We are concerned that ARB may be understating the local trade exposure risk to the industry. Gypsum board is a consistent quality, commodity material that is often transported by rail. As a consequence, gypsum board can be produced in a specific state or country and transported over land and sold in a different state or country. While ARB is correct in its assessment that gypsum board is not readily imported from or into the State of California from locations outside of North America, the Appendix K methodology and its reliance on national and regional data may be understating the potential intra-regional trade exposure for gypsum products in the State of California. ARB has not taken this attribute fully into account when assigning the risk leakage classification to the GPM industry. (GA)

Response: These comments fall outside the scope of the First 15-Day Change Notice. While no further response is required, we want to assure the commenters that we will provide a level of transition assistance designed to ensure that California businesses will not incur significant financial impacts in the beginning of the program, and to provide them with a reasonable planning horizon to begin making cost-effective emissions reductions.

As noted in the Staff Report, we are committed to monitoring how covered sectors, especially those who receive free allocation, address carbon costs once the program is in place. But, until the program is in place, we will not have the data to address the concerns raised.

Per Board Resolutions 10-42 and 11-32, we will continue to review information concerning the emissions intensity and trade exposure of different industries in California. We will recommend changes to the Board on leakage risk determinations, if needed, prior to the allocation of allowances for the second compliance period starting in 2015 for industries identified in Table 8-1 of the cap-and-trade regulation. We will update the Board annually on the status of the cap-and-trade program, including, to the extent feasible, information on shifts in business activity that may result in emissions leakage and changes in market share for covered entities and sectors.

C-87. Comment: The lime industry in California is more vulnerable to carbon leakage than the cement industry. To minimize this vulnerability, the proposed special CAF for the cement industry in Table 9-2 should be extended to the lime industry. CARB has proposed that, for the cement industry, the rate of decline of the cap should be applied only to energy-related emissions because there is no method available to reduce so called "process emissions." On this score, the lime industry is indistinguishable from the cement industry. Like the cement industry, the lime industry would need to decrease fuel-related emissions at more than twice the rate of decline of the overall cap in order for the industry to "keep pace with" the CAF proposed for all industries except the cement industry. The "chemical process" in the creation of cement referred to by CARB staff (i.e., release of CO_2 from limestone, or $CaCO_3$, also known as "calcination") is the same process inherent in the production of lime. Furthermore, lime produced in California has a lower GHG intensity than virtually all other lime produced in the United States. Because lime in California is produced with non-solid fuels, which are less GHG intensive than coal or coke, calcination emissions from the lime produced in California represent a higher percentage of total GHG emissions than the national average. Furthermore, under CARB's regulations, an industry's GHG Intensity is measured in terms of metric tons of CO_2e per million dollars of value added (CO_2e/\$M value added). As set forth in Appendix K to CARB's proposed regulation, the lime industry's GHG intensity is estimated to be 29,398 CO_2e/\$M value added, more than twice that of the cement industry. Trade intensity is defined as the value of a sector's imports and exports, divided by the value of its shipments and exports. CARB has classified the lime industry's trade intensity as low (and the cement industry's as medium). However, as recognized by CARB, in assessing an industry's overall exposure to carbon leakage, GHG intensity is far more important than trade intensity. Even if a sector is currently not exposed to foreign competition, imports from states not subject to carbon constraints (as well as foreign countries) are inevitable if a sector's GHG-related costs in California increase substantially. It is a virtual certainty that the lime industry's GHG-related costs in California will be very substantial. The industry has an extraordinary GHG intensity, and more than half of its GHG emissions are irreducible. Moreover, unlike the cement industry, the lime industry in California is already using non-solid fuels, therefore foreclosing GHG reduction opportunities through fuel switching. If the lime industry in California is subject to an unduly severe CAF, lime production will undoubtedly relocate to states or countries that do not face comparable GHG regulations. Such displacement of lime production and jobs outside the state expressly contravenes AB 32's mandate to minimize leakage to the extent feasible. Furthermore, this leakage will result in significantly greater overall GHG emissions because lime production will relocate to facilities using coal and coke, as opposed to the non-solid fuels used in California. (NLA)

Response: In the Second 15-Day Change Notice, section 95891, Table 9-2 was modified to define a different cap adjustment factor for sectors with process emissions greater than 50 percent, including nitrogenous fertilizer, cement, and lime manufacturing. In the previous proposal, we identified only cement manufacturing as an activity associated with significant level of process emissions for which no cost-effective abatement opportunities are currently available. Stakeholders in other sectors whose activities also release process emissions raised a concern in comments. After careful consideration, we determined that sectors with activities that are associated with process emissions greater than 50 percent are eligible for a lower cap adjustment factor, taking into consideration the potential impact from the emissions that do not currently have cost-effective abatement opportunities. A cap adjustment factor for all industries ensures equitable incentives to all producers to minimize leakage as a result of the cap-and-trade program.

Food Manufacturing

C-88. (multiple comments)
Comment: Food manufacturing is the only industry for which CARB has aggregated up to the 3-digit level per the North American Industry Classification System (NAICS). Every other industry is disaggregated at least to the 4-digit level. Using 3-digit level data obscures important differences among industry segments. For example, sector 3114 food processors are grouped with poultry processors in sector 3116, which have a very different energy use pattern. Food processors appear to be more energy intensive than the rest of the food manufacturing sector. Thus, the energy intensity measure for sector 3114 is diluted unless the NAICS code designations are expanded. CLFP recommends that the NAICS Code designation be expanded. (CALFP3)

Comment: We are concerned with the designation of food manufacturing processing being categorized in the “medium” Leakage Risk Classification. Additionally, food manufacturing is located in the second Industry Assistance Factor tier in Table 8-1, and should be moved to the top industry assistance factor tier due to price pressures from international markets. The Regulation states that the Industry Assistance Factor is essentially the ability an industry has to pass-on carbon costs. With low-cost competitors throughout the world, even a minimal increase in cost could displace certain market segments as demonstrated in the previously listed reports. Ag Council believes the formula for trade exposure and emissions leakage should be reevaluated to give special consideration to agricultural import and export markets. Even a minimal increase in costs could displace U.S. markets, giving more ground to domestic and international competitors. Food processing should be moved from the “medium” to the “high” leakage category in Table 8-1 due to increasing international and domestic markets. The EU’s Emission Trading System (ETS) recognized the food processing industry as being especially vulnerable to leakage. While some food processing sectors were given 100 percent free allowances, others were considered under the de-minimis category and therefore do not have to participate. California is no different as many of our commodities compete for market space in a domestic and global economy. (ACC4)

Comment: The formula for trade exposure and emissions leakage should be reevaluated to recognize the complexity and impact of agricultural import and export markets. Food processing should be moved to the “high” leakage risk category, due to increasing competition from international and domestic markets. (CFBF)

Comment: The Cap and Trade proposal has designated food processing in the “medium leakage” emissions category. ARB’s determination of the leakage category is based partly on the ability to pass on costs, coupled with domestic and international trade pressures. While it is typically difficult to pass on cost for food products, under the current economic conditions, it is even more difficult. Foreign producers enjoy the benefits of generous government subsidies and target their prices below our domestic products. California food processors are competing in a global market, and any price signal that applies to products from our State alone could cause job losses in California. We urge ARB to designate food processing in the “high leakage” category for the purposes of Cap and Trade allowances. California’s food processors are voluntarily taking steps to become more energy efficient and adopt readily available technologies. We must not put them at such a great disadvantage in the domestic or global marketplace. By granting additional flexibility to the food processing industry under the high leakage designation, we will protect the California agricultural economy by securing jobs and tax revenue for the State, as well as providing consumers with safe domestic food. (CASTLEG)

Comment: Food manufacturing is located in the second Industry Assistance Factor tier and should be moved to the top industry assistance factor tier. The Industry Assistance Factor is essentially the ability an industry has to pass-on carbon costs. With low-cost competitors throughout the world, even a minimal increase in cost could displace local U.S. markets, giving more ground to domestic and international competitors. (CFBF)

> **Response:** These comments fall outside the scope of the First 15-Day Change Notice. While no further response is required, we want to assure the commenters that we developed a system for providing appropriate level of free allowance to transition California industries to innovate toward a low-carbon economy and prevent trade risks. We are committed to protecting against emissions leakage, which will in turn protect against economic leakage. We designed the regulation to minimize leakage by placing covered entities on an equal footing with their non-covered competitors.
>
> Because of the lack of available data, aggregating the food processing industry was necessary in our analysis. Per Board Resolutions 10-42 and 11-32, we will, during implementation, continue to review information concerning the emissions intensity and trade exposure of different industries in California, and to recommend to the Board changes to the leakage risk determinations, if needed. We are committed to monitor how covered sectors address carbon costs once the program is in place. We will work with affected and interested parties to identify additional sources of information at the state level that could improve our ability to monitor leakage. Should we find that leakage is occurring or the potential for it to occur is determined despite the safeguards in the regulation, we will examine mechanisms to address leakage.

Glass

C-89. (multiple comments)
Comment: During recent discussions between GANA members and CARB staff regarding the flat glass industry benchmark, staff suggested that the flat glass industry look at the provisions made for the cement industry in terms of calculating allocations because the flat glass and cement industries have similar process emissions challenges. Like the cement industry, an average of 25 percent of the CO_2e emissions from flat glass production is from the reaction of three primary glassmaking raw materials: soda ash, limestone and dolomite. The raw batch material fed into the furnace is supplemented to the extent possible by combining it with cullet (broken glass from the downstream trimming and cutting operations of the furnace line). The ability to reduce the process GHG emissions generated from the reactions of carbon containing raw materials in the glass production process is limited, however, by two factors over which flat glass manufacturers have no control: limited availability of cullet suitable for use in flat glass furnaces to meet strict product specifications and the lack of any substitutes for the basic carbon containing raw materials. In fact, most flat glass furnaces already optimize the use of cullet to the extent possible for operational and energy efficiency reasons. The imposition of the Cap and Trade program is highly unlikely to yield or prompt any additional improvement in this regard in the near future. For these reasons and given the precedent already established for the cement industry, GANA requests CARB include a cap adjustment factor for the flat glass industry that applies the yearly reduction only to the fuel portion of the flat glass emissions as in the following Table 1. (GANA2)

Comment: Cap Adjustment Factor Table 9-2 Section 95891.
Given the approach already approved for the cement industry, PNA is proposing a cap adjustment factor for the flat glass industry that applies the yearly reduction only to the fuel portion of the flat glass emissions as in the following Table 1.

Table 1 – Cap Adjustment Factors (Existing and Proposed Flat Glass Industry)

Budget Year	**Cap Adjustment Factor (c) for All Other Direct Allocation**	**Cap Adjustment Factor (c) for Cement Manufacturing (NAICS 327310)**	**Cap Adjustment Factor (c) for Flat Glass Manufacturing (NAICS 327211)**
2013	0.981	0.991	0.986
2014	0.963	0.981	0.972
2015	0.944	0.972	0.958
2016	0.925	0.963	0.944
2017	0.907	0.953	0.930
2018	0.888	0.944	0.916
2019	0.869	0.935	0.902
2020	0.851	0.925	0.898

PNA asks that CARB consider these additional adjustments to the program to guard against flat-glass industry leakage from the state. PNA believes that TCO coated-glass production is especially susceptible to leakage, particularly to Asia. These additional adjustments would also lower the risks associated with the planned investments in the PNA Lathrop facility that would allow the site to produce coated glass products that can be used in renewable energy and energy efficient building applications. (PNA)

Comment: We understand that ARB staff has suggested that the flat glass industry review the provisions made in the Cap and Trade Rule for the cement industry with regard to calculating allocations because process emissions contribute significantly to the total emissions of both industries (section 95891, Table 9-2). Roughly 25 percent of the CO_2e emissions associated with flat glass production stem from three primary glassmaking raw materials: soda ash, limestone and dolomite. Our ability to reduce these process emissions is extremely limited. The raw batch material feed into the furnace is supplemented by combining it with cullet (*i.e.*, broken glass from the downstream trimming and cutting operations of the furnace line). The ability to reduce the process emissions generated from the reactions of carbon-containing raw materials in the glass production process is limited by availability and suitability of cullet for use in flat glass furnaces to meet strict product specifications, and the lack of any substitutes for the basic carbon-containing raw materials. For this reason, the Cap and Trade Rule is highly unlikely to yield any additional improvement in this regard in the near future. Therefore, Guardian supports the recommendation from the Glass Association of North America (GANA) that ARB establish a cap adjustment factor for the flat glass industry that applies the yearly reduction only to the fuel portion of the flat glass emissions as in the following Table 1.

Table 1 – Cap Adjustment Factors (Existing and Proposed Flat Glass Industry)

Budget Year	Cap Adjustment Factor (c) for All Other Direct Allocation	Cap Adjustment Factor (c) for Cement Manufacturing (NAICS 327310)	Cap Adjustment Factor (c) for Flat Glass Manufacturing (NAICS 327211)
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2018	0.888	0.944	0.916
2019	0.869	0.935	0.902
2020	0.851	0.925	0.898

(GIC)

Comment: PPG endorses, and hereby adopts as if set forth in full, the comments of GANA regarding the need to revise the cap adjustment factor for the flat glass industry in Table 9-2 of the proposed regulation (see section entitled “Cap Adjustment Factor Table 9-2 section 95891” in GANA letter to CARB, dated August 11, 2011). Under the harmonization of the MRR rule with federal GHG reporting requirements, process emissions from glass production (i.e., CO_2E emissions resulting from carbon in the raw materials used to make glass) will be included in a glass production facility's total reported CO_2E emissions. However, the raw materials for glassmaking are not amenable to substitutions, so the portion of total CO_2E emissions attributable to process emissions likewise will not be amenable to reduction under the annually declining cap. Other than the use of more cullet—which is a very limited option for the flat glass industry, with correspondingly limited impact on the carbon content of or emissions from the raw material batch—there are no CO_2E emission-related efficiencies that can be achieved with respect to the raw materials used in making glass. Thus, compliance with the annually declining GHG cap must be achieved almost solely by reducing combustion-related CO2E emissions. To subject the flat glass industry to the same declining cap that applies to other industries with more flexibility to reduce CO_2E process emissions would be an unfair burden. PPG fully supports GANA's proposed modifications to the cap adjustment factor for the flat glass industry, and urges the Board to adopt the revised cap adjustment factors set forth in Table 1 in GANA's August 11, 2011 comment letter. (PPG1)

Comment: While indirect emissions are not part of the proposal, any plan which does not address the negative financial impact of indirect emissions for electrical usage in the fiber glass industry will have the same negative impacts to California jobs and greenhouse gases. (NAIMA2)

> **Response:** These comments fall outside the scope of the First 15-Day Change Notice. However, with regard to the requests to change the cap adjustment factor for the glass manufacturing industry, we note that we modified Table 9-2 (section 95891) in the Second 15-Day Change Notice to define a different cap adjustment factor for sectors with process emissions greater than 50 percent. In the previous proposal, we identified only cement manufacturing as an activity associated with a significant level of process emissions for which no cost-effective abatement opportunities are currently available. However, stakeholders in other sectors whose activities also release process emissions raised a concern in comments. After careful consideration, we determined that sectors whose emissions intensity and leakage risk is high, with activities that are associated with process emissions greater than 50 percent, are eligible for a lower cap adjustment factor, taking into consideration the potential impact from the emissions that do not currently have cost-effective abatement opportunities. A cap adjustment factor for all industries ensures equitable incentives to all producers to minimize leakage as a result of the cap-and-trade program. The glass sector does not fit into the category of high emissions intensity, high leakage risk, and majority process emissions; and therefore, no adjustment is made to the cap adjustment factor for this sector.
>
> We do not believe it is necessary to add provisions to the regulation to include indirect emissions associated with electricity at this time. In the program framework, an adjustment factor was not made for power purchased in establishing the product-based benchmarks. This is because purchased power

may not create an indirect carbon cost in all California utility service territories. It is ARB's goal to see a carbon price properly embedded in all utility rates. If and when this occurs, the compensation for these indirect carbon costs could be incorporated into the product benchmarks (or reductions in these costs created in some other fashion) to help minimize leakage. We will revisit this issue once the California Public Utilities Commission proceeding addressing utility costs and revenue issues associated with greenhouse gas emissions concludes.

C-90. (multiple comments)
Comment: The State's fiber glass plants are readily subject to leakage that should entail free allowances for all three compliance periods. (NAIMA2)

Comment: Fiber glass companies should be treated the same as the other segments of the glass industry and be given 100 percent allowances for all compliance periods through 2020. Fiber glass insulation (mineral wool) has been given a medium level of allowances, which equates to 100 percent in 2012–2014; 75 percent in 2015–2017; and 50 percent in 2018–2020. The other two glass sectors (flat glass and glass packaging) received 100 percent allowances for all three compliance periods. CARB has justified that distinction based on its perception of the effect of foreign competition on each segment of the glass industry. CARB's technical appendices on leakage and allowance allocation seem to focus on international leakage (relocation of industry from California to other countries). But the statutory definition of leakage is not restricted to the international context. There is no reasonable justification for CARB restricting leakage consideration to international leakage. CARB has acknowledged the limits of its analytical approach using only international leakage. CARB should recognize that if the California fiber glass operations are not economically viable as a result of AB 32, some of NAIMA's California members might close their plants or significantly reduce capacity. The fiber glass insulation production capacity in other jurisdictions will be able to adequately supply the California market, thereby increasing emissions in those jurisdictions. This fact is particularly relevant because industry product resources are and will continue to be underutilized for many years due to current economic conditions and the downturn in the construction industry. If CARB is serious about preventing leakage from the State of California, it must carefully weigh the manufacturing potential of plants nationwide. The presence of 40-plus plants in the U.S. is the most effective argument for giving fiber glass plants 100 percent allowances for all compliance periods through 2020. NAIMA has prepared and presented detailed capacity data for the entire fiber glass industry. This detailed data demonstrated that the U.S. fiber glass industry, as a whole, has the capacity to compensate for any closure of California plants. Because CARB had previously invited this additional data and promised to consider it in calculating the Assistance Factor for allowances afforded the fiber glass industry, NAIMA was greatly disappointed and disheartened that CARB informed the industry that the data provided by NAIMA could not be considered or calculated until after the implementation of the Cap and Trade Program. CARB has assured NAIMA that application of domestic data would occur sometime in 2012 and definitely before 2014. Given the importance of this issue to NAIMA and as an indicator that CARB is in earnest about considering that data in a timely fashion, NAIMA requests that when allowances are assigned for the fiber glass industry that it convey this information relating to Assistance Factors. As an alternative, CARB could put 100 percent as a placeholder for the fiber glass industry for the second and third phases of the Cap and Trade Program. Modify Table 8-1: Industry Assistance, for Fiber Glass Manufacturing as follows:

> 2012–2014 – 100 percent
> 2015–2017 – To Be Determined
> 2018–2020 – To Be Determined. (NAIMA2)

Comment: The potential impact of AB 32 on California insulation production; the ability of existing insulation manufacturing facilities elsewhere in North America to increase or maintain their production to meet market opportunities in California; the potential for transportation-related emissions to increase if in-state insulation manufacturing is replaced by insulation manufacturing in other jurisdictions; and the absence of greenhouse gas regulations in relevant jurisdictions outside California, is most relevant and most important to developing an accurate assessment of leakage risks associated with the mineral wool sector. (NAIMA2)

Comment: Most of the out-of-state manufacturing facilities likely to increase production in response to plant closures (or manufacturing slowdowns) in California do not face any cap on greenhouse gas emissions. If insulation production were to shift from California facilities to out-of-state facilities (whether as a result of California plant closures or manufacturing slowdowns), any emissions reductions achieved in California would almost certainly be offset by emissions increases in other jurisdictions. It is entirely possible that if insulation production were to shift from California facilities to out-of-state facilities, overall greenhouse gas emissions would actually increase. First, the insulation products manufactured at California facilities tend to be of extremely high quality, and therefore provide more energy efficiency benefits to end users than do imported products from China. Second, California's manufacturing facilities are among the most energy-efficient production in the mineral wool sector. And third, the greenhouse gas emissions associated with transporting insulation products from out-of-state facilities to the California market would be extremely high (and, like the greenhouse gas emissions from out-of-state production, essentially unregulated). (NAIMA2)

> **Response:** These comments fall outside the scope of the First 15-Day Change Notice. However, with regard to the assertions that fiberglass was inappropriately categorized with respect to leakage risk, we disagree. We developed a system for free allowance allocation to provide transition assistance for industry to innovate toward a low-carbon economy and prevent trade risks. As noted in Board Resolution 10-42, we will report to the Board annually on all shifts in business activity that may result in emissions leakage and changes in market share for covered entities and sectors. If needed, we will adjust allowance allocations to correct unintended consequences.

C-91. Comment: PPG supports CARB's decision to protect flat glass manufacturing facilities in California by providing a 100 percent assistance factor in the disposition of annual GHG allowances to the industry (proposed Table 8-1). PPG believes that this decision will help to avoid emissions leakage and the lost production and lost employment that likely would otherwise occur in the flat glass industry in California in the absence of that level of assistance. (PPGI)

Response: No response is necessary.

C-92. Comment: Guardian supports ARB's proposal to offer free allocations to flat glass manufacturers in California in order to help prevent leakage from this energy-intensive, trade-exposed industry. (GIC)

Response: No response is necessary.

Hydrogen

C-93. (multiple comments)
Comment: Since liquid hydrogen is very energy-intensive and highly trade-exposed, the Panel believes liquid hydrogen should be categorized as a HIGH leakage risk. We urge ARB to maintain the distinction between gaseous and liquid hydrogen. Table 8-1 Industry Assistance should be changed to indicate that liquid hydrogen has a high leakage risk classification. We also urge ARB to recognize this distinction throughout the draft regulations and supporting documents particularly section 95114 of Attachment 1 of the Proposed 15 Day Modifications on Subchapter 10 of the "Proposed Amendments to the Regulations for the Mandatory Reporting of Greenhouse Gas Emissions". The Industrial Gases Panel is available to work with ARB staff to provide additional information on liquid hydrogen and the potential economic and environmental impacts of liquid hydrogen shipments into California. (IGPACC)

Comment: Liquid hydrogen is a different product from gaseous hydrogen used in refining applications. Liquid hydrogen serves different downstream manufacturing operations, is readily transportable across California borders and requires additional production methodology and equipment. Further, liquid hydrogen production has a material indirect GHG emission footprint due to the significant electricity consumed in the liquefaction process. For this reason, liquid hydrogen should be treated as a distinct product with its own unique product benchmark. Since liquid hydrogen is very energy intensive and highly trade exposed, we believe liquid hydrogen should be categorized as a "High" leakage risk. (APC2)

Comment: CARB should classify liquefied hydrogen production as a high leakage activity because it is highly energy and emissions intensive. Characterizing liquefied hydrogen as a medium leakage risk will impose a significant CO_2 compliance obligation, which will provide a strong competitive advantage to out-of-state competition that can easily truck or rail liquefied hydrogen into California and elsewhere in the United States. Such displacement of hydrogen production would create economic and jobs impacts in

California and would increase overall CO_2 emissions levels due to increased vehicle traffic. (PRAXAIR2)

> **Response:** We agree that liquid hydrogen should be added to Table 8-1 as a separate activity under industrial gas manufacturing. Liquid hydrogen was given industry assistance factors for all three compliance periods based on a medium leakage risk classification. We are committed to protecting against emissions leakage, which will in turn protect against economic leakage.
>
> Per Board Resolutions 10-42 and 11-32, we will, during implementation, continue to review information concerning the emissions intensity and trade exposure of different industries in California, and to recommend to the Board changes to the leakage risk determinations, if needed. We are committed to monitor how covered sectors address carbon costs once the program is in place. We will work with affected and interested parties to identify additional sources of information at the state level that could improve our ability to monitor leakage. Should we find that leakage is occurring or that the potential for leakage exists despite the safeguards in the regulation, we will examine mechanisms to address leakage.

C-94. Comment: Liquid hydrogen should be categorized as a high leakage risk. (IGPACC)

> **Response:** We believe that our leakage risk determination for liquid hydrogen as medium is supported by available data and is expected to be protective of leakage risks. Leakage risk is classified using emissions intensity and trade exposure as central measures.
>
> We analyzed emissions intensity data for all industrial sectors. We then selected natural break points in the emissions intensity spectrum. Industrial sectors are placed into the high, medium, and low categories of emissions intensities based on these break points. For assessing trade exposure we considered various approaches before choosing trade share as the metric to classify industrial sectors for trade exposures.

Refineries / Oil & Gas

C-95. (multiple comments)
Comment: CARB should classify the California refining sector as "high risk" for emission leakage through 2020 and issuance allowances on this basis. Crude oil and petroleum products are world commodities with strong competition in energy markets. Exposing California refiners to the additional cost of carbon from process emissions will place these local businesses at a disadvantage relative to international manufacturers. (CONOCO2)

Comment: The refining industry is clearly under trade pressure from fuel imports. The proposed reduction of the Assistance Factor from 100 percent in the first compliance period to 75 percent and then 50 percent in the subsequent second and third compliance periods, respectively, leaves in-state production capacity vulnerable to increased dependence on imports (and hence supply disruptions and the loss of jobs within the state). Industry experts anticipate this import pressure to materially increase over the next several years, thereby increasing the industry sectors leakage risk to “High”, where no reduction in the Assistance Factor would be imposed. (APC2)

Comment: The California refining industry is heavily trade exposed and clearly subject to leakage because refined products can, and regularly do, enter the state from refineries in other regions and from international sources. The California refining industry should be classified as a Highly Trade Exposed Industry, and not as a Moderately Trade Exposed Industry. ARB staff has been made aware of discrepancies in census economic data, discrepancies between CEC data (which more accurately reflects the full slate of California refinery products) and EIA data that reflects only a portion of the sector. These discrepancies as well as new commodity flow data suggest a more robust review of trade exposure for refining is in order. We believe that a comprehensive review of these issues will lead ARB to conclude that the California Refining Industry is Highly Trade Exposed and should be treated as such in the Cap and Trade Regulation. ARB Staff should convene a public process to review recent federal and state trade and commerce and energy data from federal and State sources and re-evaluate the trade-exposure of the California refining industry. (WSPA3)

Comment: The Regulation correctly acknowledges the reality that California industry will be subjected to trade exposure as a result of the Cap and Trade program. California industry will be competing against global and interstate competition that are not similarly regulated, and are therefore not subject to the same costs. Competitive pressure resulting from trade exposure to unregulated parties can be especially acute in state or regional programs in the form of both neighboring states *and* international competition, particularly in coastal states such as California where there is ready access to international trade infrastructure like the California Ports facilities. If not properly and adequately mitigated, this trade exposure can and will result in leakage of both emissions and jobs from California to unregulated areas. While acknowledging the need to address trade exposure through free allocation, the Regulation includes a very quick path to auction of some 50 percent of refinery allowance needs by 2018. CARB staff appears to use a simplistic, static model that assesses market dynamics before the imposition of a carbon price and assumes little or no change in behavior resulting from the carbon policy. This static model also ignores the cumulative impact of other regulations and other differences in operating cost between California industry and its competitors. CARB’s analysis also fails to consider the competitive effects of California produced product that is exported to neighboring states. This is an inadequate and deeply flawed method for informing a critical part of the design of the Regulation. A recent study evaluated the leakage potential for the U.S. refining industry resulting from a carbon policy. The EnSys study models the impact on the refining industry of the allocation scenario contained in the federal Waxman-Markey (WM) proposal—a proportion of free allocation that approximates the 50 percent in 2018 contained in the CARB Cap and Trade Regulation. Rather than taking a static look at behavior before and after the imposition of a carbon price, the EnSys model projects how industry is likely to operate under a given scenario. The EnSys study concludes that because this sector operates as part of and interacts within the global refining industry, "the impacts of WM on US refining and US petroleum imports dependency would be substantial" in that it "de-levels" the playing field in the global refining sector. The study concludes "the underlying reason the potential impact on US refining is so severe is that allowance costs substantially raise operating and capital costs of US refineries, rendering them less competitive versus non-US refiners in regions that do not bear any carbon costs." The impact on coastal refineries, such as those in California, is especially pronounced. (BP2)

Comment: The California refining industry should be classified as a High Intensity Trade Exposed Industry, and not as a Moderately Trade Exposed Industry. The California refining industry is heavily exposed to market leakage since refined products can enter California from out-of-state and international refineries operating under less stringent environmental standards with little to no market barriers. An objective review of the information and data provided to ARB will lead to the conclusion that the California Refining Industry is Heavily Trade exposed and should be treated as such in the Cap and Trade Regulation. ARB has been provided information which identifies discrepancies in census data and discrepancies between CEC data that more accurately reflects the full slate of California refinery products. ARB has also been provided information which identifies discrepancies in EIA data which does not accurately reflect the full slate of California refinery products. This data highlights the importance of exports to Arizona and Nevada (states which can import products from the Rocky Mountains or Gulf Coast), and likely serves as the basis for the artificially low estimates of the energy intensity attributed to the California Refining Sector. Tesoro has attached a graph from Facts Global Energy which represents refineries that have been for sale, sold or shutdown since 2008 by region of the world. The EU has had the most plants both for sale and shutdown which is consistent with the competitive disadvantage of their markets from importation of fuels originating from countries such as India that are not subject to GHG and other regulatory costs. The graph shows North America as having the 2nd most plants shutdown for many of the same reasons; imported fuels taking market share in an oversupply situation. This graph supports the conclusion that refined products move and trade across the globe negatively affecting competitive markets making California refineries highly trade exposed. (TESORO2)

Comment: The oil and gas sector is part of a complex world marketplace with prices set beyond the control of any market player or government for that matter. Actions in the regulatory sphere have the distinct possibly of acute leakage if not handled properly. As noted, California production is subject to the highest levels of environmental review and oversight. If the AB 32 regime gets it wrong and skews the economics of domestic production it will lead to widespread curtailment of domestic production, which in turn, will lead to increased use of imported crude feedstocks, crude produced under less stringent environmental controls. Leakage remains a distinct possibility from the sector considering the considerable uncertainty posed by the development of a California only Cap and Trade regime. (CIPA)

Comment: ARB's proposed revisions propose a refining industry "assistance factor as determined by the leakage risk of the product" that would be used with ARB's benchmark in an equation (section 95891) allocating free emissions allowances. The intent and effect of this assistance factor is to exempt the California refining industry from having to purchase emissions allowances for 100 percent of its emissions through 2014 and the vast majority of its emissions through 2020. ARB's rationale for is that this assistance factor is to prevent or manage "leakage." ARB claims that if California refineries are required to buy emissions credits, then this will reduce their profits so much that they will partially or fully shut down production; refineries elsewhere will increase production and ship gasoline, etc. to California instead; and that will result in equal or greater total emissions because refineries elsewhere are as dirty as California refineries or dirtier. ARB provides no evidence that this has happened despite decades of refinery environmental requirements here and elsewhere. It provides no evidence that California refineries will reduce production due to the cost of ARB's emission credits. It provides no evidence of the capacity or costs of increasing refinery production elsewhere and then shipping products instead of crude. As part of the latter failure, ARB fails to present analysis of increased costs for shipping motor fuels due to the volume expansion of the fuels over that of crude and/or their increased volatility and fire hazard. ARB does not even show the possibility of the impact it claims because it provides no evidence of equal or higher average emissions intensities at refineries outside California. With respect to the California refining industry, ARB's "leakage risk" rationale lacks factual or scientific support. (CBE2)

Comment: (Subsequent correspondence from the commenter indicated an error in the original submission that has been corrected in this comment) ARB ignores substantial evidence that its assistance factor is incorrect. Review of data on imports, exports, and movements of refined products shows that California has become and remains a net exporter of gasoline and other refined products. This shows that decades of refinery environmental requirements in California which often were the first of their kind and/or most progressive anywhere have not resulted in any sign of the "leakage" problem that ARB now claims will occur.

ARB ignores this evidence that its assistance factor analysis is incorrect. Long-term major capital commitments to expanded and continued refining infrastructure have been built in recent years at California refineries in El Segundo, Wilmington-Carson, Benicia, Martinez, Rodeo, Richmond and Bakersfield. ARB ignores this evidence. At least one well documented measure could reduce statewide refinery emissions by approximately 20 percent or 7.8 million tonnes per year below current levels by 2020 for about 80 cents per barrel crude. However, ARB's proposed emissions credits would be even cheaper and more profitable for refineries. Considering that refinery crude costs have fluctuated by nearly $100 per barrel in recent years while California fuels production stayed here, this evidence indicates ARB's leakage concern is misplaced. Further, ARB's own U.C. advisors warned that including the oil industry in a multi-sector Cap and Trade scheme will not work because oil companies would buy the allowances instead of clean up since oil is so firmly and uniquely entrenched. Instead of forcing them to shut down, ARB's allowance price will not even make refineries clean up. Finally, ARB ignores the California refining industry's extreme-high emissions intensity and the lower average emissions intensity in every other U.S. refining region. ARB inappropriately ignores the fact that, even if California refinery production was replaced by large increases in fuels imports from refineries elsewhere, which will not happen as shown above, total emissions could be reduced due to the lower emissions intensities of refineries elsewhere. Thus, the equal shift or increase in emissions ARB fears is impossible in the first place. It is not appropriate for ARB to ignore substantial evidence that its assistance factor is incorrect. (CBE2)

Comment: Classification of Leakage Risk for Petroleum Refineries and Industrial Gas Manufacturing should be designated as "High" as defined in section 95870(e) of the 15-Day Modification Package and consistent with the criteria employed in Appendix K of October 2010 Proposed Rule. At a minimum, CARB should re-evaluate the leakage risk preceding each subsequent compliance period and determine if the proposed reduction in the Assistance Factor is warranted. (APC2)

Comment: ARB's assistance factor would seek to maintain or increase California refinery fuels production. ARB assumes that if California fuels production is reduced it will be replaced by equally or more carbon-intensive fuels produced elsewhere. In contrast, ARB's Low Carbon Fuel Standard (LCFS) was established to replace high-carbon fuels, primarily refined petroleum fuels, with low-carbon fuels, targeting a 10 percent reduction in transport fuel cycle emissions by 2020. If the LCFS replaces refinery fuels with lower carbon fuels, equal or higher-emission fuels would not replace them. Thus, unless ARB assumes that its LCFS will fail, it will be impossible for ARB's assistance factor assumption to be realized. Conversely, if ARB's assistance factor succeeds in maintaining or increasing California refinery fuels production, the success of the LCFS will be impossible. Therefore, ARB's assistance factor for refineries and its LCFS are in direct and irreconcilable conflict. ARB cannot have it both ways. ARB inappropriately ignores this clear evidence that its assistance factor is unnecessary and inappropriate. (CBE2)

> **Response:** These comments fall outside the scope of the First 15-Day Change Notice. While no further response is required, we want to assure the commenters that we developed a system for providing an appropriate level of free allowances to transition California industries to innovate toward a low carbon economy and prevent trade risks. We are committed to protecting against emissions leakage, which will in turn protect against economic leakage. We designed the regulation to minimize leakage by placing covered entities on an equal footing with their non-covered competitors, with an appropriate level of allowance allocations.

Per Board Resolutions 10-42 and 11-32, we will, during implementation, continue to review information concerning the emissions intensity and trade exposure of different industries in California, and to recommend to the Board changes to the leakage risk determinations, if needed. We are committed to monitor how covered sectors address carbon costs once the program is in place. We will work with affected and interested parties to identify additional sources of information at the state level that could improve our ability to monitor leakage. Should we find that leakage is occurring or that the potential for leakage exists despite the safeguards in the regulation, we will examine mechanisms to address leakage.

In our second 15-day changes to the regulation, based on additional information provided by stakeholders, we updated Table 8-1 with a change to reclassify coke calcining as a high-leakage risk activity, and we inserted a new approach for allocation to the petroleum refining sector in section 95870(d)(2)(A-B) in response to a stakeholder comment. In the first compliance period, a total amount of allowances will now be assigned to the refining sector. This sector allocation will then be divided among individual refiners using the new method specified in section 95891(d). In the second and third compliance period, there will no longer be a sector allocation determined for the refining sector. The amount allocated to each individual refinery will be based on the product output-based allocation approach and the "CO_2 weighted ton" benchmark. These changes and the associated impacts are detailed in Appendix A to the Second 15-Day Change Notice.

Under the new text, complex refiners' allowances are allocated based on a methodology initially proposed by the Western States Petroleum Association. This approach allocates allowances based on the following factors: (1) historical emissions from for each refinery, (2) the Solomon Energy Intensity Index (EII) for each refinery, (3) an adjustment factor to reduce competitiveness impacts of allowance allocation between in-state refineries, and (4) future emissions for each refinery.

Solar

C-96. Comment: Solar remains concerned about the assistance factor category for our industrial sector. We recommend staff further evaluate the mechanisms for evaluating Trade Exposure for our industry sector. It is our understanding that staff will be revisiting leakage. We look forward to working with them in 2012, or sooner if possible. (SOLARTURBINES3)

Response: This comment falls outside the scope of the First 15-Day Change Notice. No further response is required.

Other Allocation-Related Comments

C-97. Comment: Section 95890(c) should not be removed until ARB has decided how to allocate allowances to natural gas utilities for the protection of their small customers. Section 95893 is still reserved for Allocation to Natural Gas Distribution Utilities for Protection of Natural Gas Customers, so when ARB addresses that question it should have this subsection available so as to not limit the potential methods of distributing allowances to individual natural gas utilities. Modify section 95890(c) as follows:

> <u>(c) Reserved for Natural Gas Distribution Utilities.</u> (SEMPRA3)
>
> **Response:** We removed this section for clarity. We are committed, per Board Resolution 11-32, to continue discussions with stakeholders on the issue of allowance allocation issues associated with emissions from natural gas combustion. We note that (1) the decision has not been made to allocate allowances to Natural Gas Distribution Utilities and (2) the importance of the price signal in motivating greenhouse gas reductions in this sector.

C-98. Comment: ARB's refinery benchmark and assistance factor increase costs to the public. The excess emissions from California refineries that would result from ARB's flawed proposal will increase the emissions reduction burden on other sectors, cause failure to meet total climate emissions targets, or both. ARB inappropriately ignores this potential for increased emissions to increase health impacts and related costs to Californians. ARB also inappropriately ignores the higher jobs factors for the other sectors that would be burdened with making deeper emissions cuts if ARB exempts oil refining as proposed. U.S. Economic Census data show that the refining industry is next to last in jobs per dollar annual sales, shipments, receipts or revenue. Other major employment sectors such as public transportation and manufacturing of the green technology refiners might buy should they be required to clean up create more than ten times as many jobs per dollar. Thus, ARB's proposed windfall for oil refineries will not only poison us, it will result in less future job opportunities for Californians. ARB ignores these costs. (CBE2)

> **Response:** The benchmarks and assistance factors are based on similar methods as those used in other market programs. The cap-and-trade program is not expected to increase emissions, and all stationary sources such as refineries are still subject to all other local and state laws that limit their air emissions. The declining cap provides certainty that overall GHG emissions will be reduced in California for the covered sectors. Oil refineries are not exempted from the program, as suggested in the comment. They will be subject to the declining cap and will have to compete for the declining number of allowances each year as the program is implemented. The cap-and-trade program provides certainty for investment in green technology and green jobs in California. We disagree that the benchmarks will provide a windfall for oil refineries.

D. AUCTION

Disposition of Allowances - Advance Auction

D-1. Comment: Section 95870(b) changes the Auction Reserve transfer requirement from two percent to 10 percent. WSPA does not understand the need for this increase. WSPA recommends that the two percent transfer authority be retained. (WSPA3)

> **Response:** We modified this section to allow covered entities facing a greatly expanded compliance obligation in the second compliance period to physically hedge their future compliance needs without needlessly tightening the supply of allowances in the first compliance period.

D-2. Comment: EDF supports the proposed increase of the advance auction from two percent to ten percent, as long as this advance auction cannot be turned into a form of an implicit borrowing. Although these advanced emissions allowances can only be used in the credit period from which they were purchased (thus leading to price discovery of that period), the extra amount of emissions available for trading at an early time makes the presence of a robust allowance tracking system at the outset even more important. We do not foresee significant problems with allowing a larger percentage of allowances to be auctioned in this pool and believe that the forward auction will provide benefits beyond that of simple price discovery, such as raising additional funds for energy efficiency investment and community benefits. (EDF4)

> **Response:** No response is needed.

Unsold Allowances

D-3. (multiple comments)
Comment: SMUD continues to suggest that current vintage allowances that remain unsold at auction remain in the Auction Holding Account for a reasonable period, rather than being transferred to the Containment Reserve Account. The slight change necessary for conformance with the change in section 95857(d) is to section 95831(b)(4), which establishes an Allowance Price Containment Reserve Account, and states that the serial numbers of allowances used to fulfill an entity's excess emissions obligation pursuant to section 95857(d) will be transferred to this account. This subpart of section 95831 is no longer necessary and should be deleted. SMUD also suggests that allowances that remain unsold in a quarterly auction should be returned to the Auction Holding Account unless the unsold allowances are from a vintage at least one year prior to the auction in which they remain unsold. Unsold allowances in one auction do not necessarily imply that subsequent auctions will also have unsold allowances, particularly with lumpiness in allowance allocations and in investments that reduce need for allowances. Here, and in Section 95911, the regulations should be modified to keep unsold allowances in the Auction Holding Account until it is reasonably clear that they are not required in current auctions. Transferring to the Allowance Price Containment

Reserve Holding Account prematurely simply is a recipe for ratcheting up allowance prices unnecessarily. Modify section 95831(4) and 95991 as follows:

> (4) A holding account to be known as the Allowance Price Containment Reserve Account:
>
> > (A) Into which the serial numbers of allowances allocated by ARB for auction that remain unsold at auction in the year following their vintage year will be transferred.;
> > ~~(B) Into which the serial numbers of allowances directly allocated to the Allowance Price Containment Reserve under subarticle 8 pursuant to section 95870(a) will be transferred.~~;
> > (B~~C~~) Into which the serial numbers of allowances submitted to fulfill an entity's excess emissions obligation pursuant to section 95857(d)(c) will be transferred~~.~~; and
> > (C~~D~~) From which the Executive Officer will authorize the withdrawal of allowances for sale to sell to covered entities pursuant to section 95913.
>
> (4) Disposition of Allowances Allocated for Auction when an Auction Settlement Price Equals the Reserve Price.
>
> > (A) Unsold ~~current vintage~~ allowances from a vintage prior to the current year shall be transferred equally to the three tiers in the Allowance Price Containment Reserve Account. If the number of allowances unsold is not divisible by three, the transfer of the final allowances shall be to the lowest priced tier.
> > (B) Unsold future and current vintage allowances auctioned pursuant to section 95910(c) will be returned to the Auction Holding Account for sale at the next auction. (SMUD3)

Comment: The Allowance Reserve is not the proper place for any allowances unsold at auction, paid as penalties, or removed from the Voluntary Renewable Electricity Reserve Account. In each of these cases, the allowances should be returned to the general market via quarterly auction. First ARB staff has expressed concern that returning allowances unsold at auction to future auctions would only continue to produce an oversupply of allowances in these future auctions. However, due to the intrinsic nature of discrete quarterly auctions, allowance demand and resultant auction clearing prices will likely fluctuate significantly in response to external factors. Even if allowance demand is thin in one quarter, it may not always be thin. Instead, the quantity demanded in future auctions will respond to many conditions, such as weather, fuel prices, or offset availability. For example, the electricity industry may demand more allowances than average in the third quarter of a very hot year as electricity demand increases across the State. However, compliance entities may not have been able to predict such weather-related conditions in previous auctions and procure enough allowances to fill their high need. Simply because demand in the market was not high enough to clear at $10, the regulated community should not then be forced to pay Allowance Reserve prices—$40 or more—in the future. (SCE3)

Comment: PG&E appreciates the change ARB made to move unsold future vintage allowances to the Auction Holding Account for sale at the next auction, and PG&E believes similar treatment should apply to current vintage allowances. PG&E has concerns with the proposal described in 95911(b)(4) to move unsold current vintage allowances that are not from the Limited Use Holding Accounts to the three APCR tiers in equal proportion. While dividing them equally among the tiers is better than the previous proposal to move them to the highest tier, PG&E continues to advocate that these unsold allowances be allocated to the next auction instead of the APCR. Unsold allowances in one auction are not necessarily indicative of a long-term oversupply. Modify section 95911(b)(4)(A) as follows:

> (A) Unsold current vintage allowances ~~shall be transferred equally to the three tiers in the Allowance Price Containment Reserve Account. If the number of allowances unsold is not divisible by three, the transfer of the final allowances shall be to the lowest-price tiers.~~ auctioned pursuant to section 95910(c) will be returned to the Auction Holding Account for sale at the next auction. (PGE4)

> **Response:** We made changes to section 95857(d) to transfer allowances used to cover an excess emissions obligation to the auction holding account. We also made a change to section 95831(b)(4) to eliminate this source of allowances from the provisions used to define the Allowance Price Containment Reserve. Instead, we added this source of allowances to section 95831(b)(2), which defines the auction holding account.
>
> We did not make the changes recommended by the commenter to have the allowances remaining unsold at auction be held in the auction holding account for sale at the next auction. We disagree with the assertion in the comments that the auctions will quickly dissipate any oversupply of allowances. Instead, we added provisions to section 95911(b)(4) to direct that unsold allowances would be held in the auction holding account and only returned to future auction if (1) two auctions achieve an auction settlement price above the auction reserve price, and (2) the amount of unsold allowances returned to auction does not increase the number of allowances to be auctioned by more than 25 percent.

D-4. (multiple comments)
Comment: We ask that ARB retain the provision directing allowances unsold at auction to the allowance price containment reserve. In place of the reserve, a few stakeholders at the July 15, 2011, workshop on the Discussion Draft suggested these allowances be made available at the subsequent auction. We agree with staff's position that this could facilitate consistent over-allocation of allowances and inhibit price discovery. Rather than lock-in a mechanism that could lead to consecutive auctions clearing at the floor price, a pitfall of the Regional Greenhouse Gas Initiative (RGGI) system that ARB should strive to avoid, the most appropriate use of unsold allowances is to backfill the allowance reserve. The program's banking provisions provide ample opportunity for entities to guard against the risk of future allowance shortages; should market conditions lead to an unexpected shortage. However, ARB has designed the allowance

reserve to introduce additional liquidity. It is vital that ARB maintain a provision to fill the reserve (when allowance prices are at the floor) to provide the cost-containment function of the reserve as envisioned if allowance prices spike. (KUSTIN16)

Comment: CE2 supports the language in sections 95911(b)(4)(A) and (B) that requires unsold current vintage allowances to be transferred to the Price Containment Reserve, equally to the three tiers. We recommend unsold future vintage allowances should also be transferred to the Price Containment Reserve rather than returned to the Auction Holding Account. (CE2CC)

> **Response:** We agree that the method of handling allowances remaining unsold at auction must not perpetuate an oversupply of allowances. However, we disagree that the only way to do this is to transfer the unsold allowances to the reserve. We contend that the new provisions of section 95911(b)(4) will keep the unsold allowances out of the auction until the oversupply has been cleared. This will help limit price increases below the reserve.

D-5. Comment: Section 95911(b)(4)(A) and (B) proposes to deposit unsold allowances from the current vintage to the Allowance Price Containment Reserve Account. MSCG recommends a modest variation to this approach. We believe that a provision allowing auction participants to provisionally bid for amounts above the otherwise applicable purchase limits would be beneficial. Such provisional bids would only be filled if some quantity of allowances would otherwise go unsold. Only then, after filling both "standard" and provisional" bids, should unsold allowances be deposited in the Allowance Price Containment Reserve Account. Such an approach would better meet the needs of the market, without increasing any concerns related to market concentration (holding limits would still be applicable) or undue impact on price, or ability of compliance entities to fairly gain access to allowances in auctions. If allowances in an auction would otherwise go unsold, one party buying a quantity in excess of otherwise applicable purchase limits cannot have an undesirable negative impact on the market. Similarly, if adopted, the same type of provision would be equally useful in the future vintage allowance auctions. (MSCG3)

> **Response:** We agree that the approach suggested in the comment would increase market liquidity by getting allowances to entities that value them. However, we believe the revised procedure for returning unsold allowances to future auction will accomplish that end without the risk of perpetuating market oversupply. The new provisions of section 95911(b)(4) will keep the unsold allowances out of the auction until the oversupply has been cleared.

D-6. Comment: We recommend that ARB revise the heading of section 95911(b)(4) to remove "when an Auction Settlement Price Equals the Reserve Price." Given the auction rules, see section 95911(d)(4), there may be times when there are unsold allocated allowances and the Auction Settlement Price does not equal the Reserve Price. (PGE4)

Response: While we agree that allowances can remain unsold when the auction settlement price is above the auction reserve price, all unsold allowances never leave the auction holding account. The process of re-auctioning the allowances is also not affected. Also, the title of this section does not circumvent or conflict with any other requirements of the regulation as the title itself does not require any action.

D-7. Comment: PG&E recommends ARB further define what occurs when there are unsold consigned allowances. According to section 95911(b)(3)(B), when the auction clears at the auction reserve price, allowances are sold in equal proportion from each consigning entity. As per (b)(5)(A) "Allowances consigned to auction from limited use holding accounts that remain unsold at auction will be returned to the respective source accounts." To address the situation in which the proportion returned does not result in a whole number of sales from a consigning entity, PG&E recommends ARB sell in proportion to the consigned quantity rounded down. After that, the remaining consigned allowances are each assigned a random number and selected to be sold beginning with the lowest number until quantity supplied matches quantity demanded. The consigned allowances that are not sold are then returned to the respective source accounts. Modify section 95911(b)(3)(B) as follows:

(B) When there are insufficient winning bids to exhaust the allowances from a consignment source in section 95911(b)(3)(A), the auction operator will sell an equal proportion of allowances from each consigning entity rounded down. If, as a result of rounding down, there are fewer allowances sold than demanded, then the auction operator will assign a random number to each unsold bundle of 1,000 metric tons of CO_2e from a consignment source in section 95911(b)(3)(A). Beginning with the lowest random number assigned and working in increasing order of the random numbers assigned, the auction operator shall sell allowances assigned the random number until the quantity of allowances sold equals the quantity of allowances demanded. (PGE4)

Response: We disagree that the change is needed. We would always be able to find a whole number to use when calculating how many allowances to sell from each consignment source. There is, therefore, no advantage to the proposal.

Allowance Price Containment Reserve

D-8. Comment: PG&E is concerned that ARB may allow covered entities in potentially linked GHG emissions trading systems to buy from the APCR. By allowing entities from outside of California access to the APCR, it is possible that the price protections for Californians, including California electric distribution ratepayers, may be compromised. PG&E views this as a critical issue in the overall design of any linkage with other programs. (PGE4)

Response: Section 95913 contains provisions implying that non-California entities in ETS to which California has linked could access the reserve. However, we anticipate that the linked systems would have similar Reserve provisions. If they do not, then the reserve may have much less ability to buffer price increases. We expect that, since linkage will be accomplished through a subsequent regulatory project, the linking regulation will specify how the reserve will operate in the linked programs.

D-9. Comment: ARB noted that their goal in making changes to section 95913 was to simplify and allow the APCR to fill from the lowest price. PG&E agrees with this objective, but the changes as written in the Regulation do not allow for bids to clear from the Reserve efficiently. Modify section 95913(c)(3)(A), 95913(e)(2)(E), and 95913(f) as follows:

(A) The first Reserve sale will be conducted on March 29 ~~8~~, 2013.

(E) The financial services administrator will evaluate the bid guarantee and inform the reserve sale administrator of the value of the bid guarantee once it is found to conform to this section and is accepted by the financial services administrator. The financial services administrator will also inform the bidding entity at least 5 days prior to the auction date if the bid guarantee is found to conform to this section and is accepted by the financial services administrator.

Section 95913(f).

(f) Purchase Determinations.

(1) The reserve sale administrator will conduct sales from each tier in succession, beginning with the lowest to the highest priced tier, until either all allowances are sold from the reserve or all the accepted bids are filled.

(2) The reserve sale administrator will only accept a bid

(A) If acceptance of the bid would not result in violation of the holding limit pursuant to section 95920(b); or

(B) If acceptance of the bid would not result in a total value of accepted bids for a covered entity greater than the value of the bid guarantee submitted by the covered entity pursuant to section 95913(e)(2).

(3) If the sum of bids at the tier price, including bids at prices in higher tiers, which are accepted by the reserve sale administrator is less than or equal to the number of allowances in the tier, then:

(A) The reserve sale administrator will sell to each covered entity the number of allowances for which the entity submitted bids for that tier, including those at higher priced tiers, which were accepted by the reserve sale administrator.

~~(B) If allowances remain in the tier after the sales pursuant to section 95913(f)(3)(A) are completed, the reserve sale administrator will assign a random number to each bundle of 1,000~~

~~allowances for which entities submitted a bid for the tier above the current tier being sold. Beginning with the lowest random number assigned and working in increasing order of the random numbers assigned, the reserve sale administrator shall sell allowances to the bidder assigned the random number until the remaining allowances in the tier are sold or all bids have been fulfilled.~~

(4) If the sum of bids accepted by the reserve sale administrator for a tier, including bids at prices in higher tiers, is greater than the number of allowances in the tier, the reserve sale administrator will determine the total amount to be distributed from ~~each~~ the tier to each covered entity using the following procedure.

(A) The reserve sale administrator will calculate the share of the tier to be distributed to each bidding entity by dividing the quantity bid by that entity and accepted by the reserve sale administrator by the total quantity of bids which were accepted by the reserve sale administrator; and

(B) The reserve sale administrator will calculate the number of allowances distributed to each bidding entity from the tier by multiplying the bidding entity's share calculated in section 95913 (f)(2)(A) above by the number of allowances in the tier, rounding the number down to the nearest whole number.

(C) If allowances remain in the tier after the sales pursuant to section 95913(f)(4)(B) are completed due to the rounding down of each bidding entities share, the reserve sale administrator will assign a random number to each bundle of 1,000 allowances for which entities submitted a bid for the tier, including bids at prices in higher tiers, that was not fulfilled. Beginning with the lowest random number assigned and working in increasing order of the random numbers assigned, the reserve sale administrator shall sell allowances to the bidder assigned the random number until the remaining allowances in the tier are sold.

(5) After completing the sales for each tier the reserve sale administrator will repeat the processes in sections 95913(f)(3) and (f)(4) above for the next highest price tier, considering bids in those higher priced tiers adjusted for any allowances awarded in sales of the lower priced tiers, until all bids have been filled or until the Reserve is depleted. At that time the reserve sale administrator will inform the Executive Officer of the sales from the Reserve to each participant. (PGE4)

Response: We agree that a clearer and more efficient system is needed for purchases from the reserve and revised the procedure in section 95913(e) of the regulation. However, the new procedure is different than the one proposed in the comment.

In the new procedure, each bidder specifies a single bid price and quantity. Beginning with the lowest priced tier, the administrator will fill bids made at that tier price. If any allowances remain, they will be used to fill bids placed at the next higher tier price. This process is repeated until all allowances are sold or all bids are filled. While this is not the same as the procedure proposed in the comment, we believe that it serves the same purpose in allowing bidders to purchase the cheapest allowances available.

We disagree with the suggestion that the financial services contractor be given only five days to make a decision on whether the bid guarantee is acceptable. Turnaround time will depend on workload, and we will not jeopardize the integrity of the auction to meet an arbitrary timeline.

D-10. (multiple comments)
Comment: Changes were made to section 95913, governing the sale of allowances from the Allowance Reserve, to clarify the bidding process. The bidding process for the Allowance Reserve should identify each regulated entity's maximum willingness-to-pay for Allowance Reserve allowances. Once this willingness-to-pay is identified, in order to facilitate low-cost compliance, all bids should flow down to the lowest available price level. In essence, entities with a higher willingness-to-pay should not necessarily have to pay more for these allowances if they are available at lower prices, which SCE believes was the intent of the changes to section 95913. SCE supports the increased flexibility, allowing bids to be filled from the lowest tier first, but ARB should clarify section 95912(f)(1) to confirm that the clearing price for filled bids is the tier price, not the bid price. (SCE3)

Comment: Section 95913(f)(3)(B) specifies the procedure for selling remaining allowances at one tier level to bidders at the next higher tier level, but does not specify if such sales are to be made, which prices will be used. The provision should explicitly state if the price of the tier from which the allowances remain or the price from the higher tier from which bidders are randomly selected applies to the sale of such allowances. (SCAQMD4)

Response: We agree with the comment, and modified section 95913(f)(3)(B) so that the price charged to the bidder will be the price of the tier from which the allowance is sold, not the price bid.

D-11. Comment: It is likely that there will be participants in Reserve auctions that will request bids at multiple tiers with the caveat that if a bid is accepted at a lower-priced tier that the bid(s) at higher-priced tiers be inactivated. Section 95913(e)(1) should explicitly allow or explicitly disallow this type of bidding. If it is allowed, section 95913(e)(2) should include a provision for the bid guarantee in such cases to adequately cover the most expensive potential result rather than the sum of all bids (e.g., if bids are placed at three tiers but a maximum of two bids are to be accepted, then a bid guarantee in the sum of the two highest bids would be sufficient). (SCAQMD4)

Response: Section 95913(e)(1) clearly states that bidders submit a single bid price and a single quantity. There is no mention of the bid process suggested by the commenter.

Reserve Floor Price

D-12. Comment: The $10 California GHG auction reserve price has no basis. ARB should provide the rational for how the $10 price was determined. If ARB is interested in a true market-driven system, the open market should determine the allowance price. (VALERO2)

Response: The auction reserve price is one of the components of a linked regional market program for which consistency across the individual programs is especially important. For this reason, we will work closely to evaluate this issue with other WCI jurisdictions when evaluating their programs for possible linkage. We may propose an adjustment to the reserve price as part of changes made to link California's program with the programs established by WCI partner jurisdictions.

We chose the $10 reserve price for two reasons. First, we are concerned that through recessionary economic conditions or forecasting error the cap-setting procedure may accidently lead to the creation of excess allowances. Throughout the regulatory process, we heard concerns from environmental groups that the cap would be unintentionally set too lax—a condition sometimes referred to as oversupply or over-allocation. The over-allocation condition occurs if too many allowances are supplied to covered entities relative to expected business-as-usual emissions levels. If the cap is set too loose, prices will be lower than expected, and a weakened incentive to reduce emissions will be created. The reserve price mechanism would correct this condition by transferring excess allowances to the Allowance Price Containment Reserve, where they will be available in times of high prices. Second, we are adapting the approach used in the federal Waxman-Markey proposal (HR 2454), which proposed a reserve price of $10 with an inflator mechanism of five percent per year plus inflation.

Finally, we do not consider the prices observed in markets, such as RGGI, as representative of the marginal cost of abatement or production of offsets. These prices are instead the result of the over-allocation problem that we are determined to prevent in California. We note that the RGGI auction reserve price, which follows market prices, has not corrected for the oversupply. We have been clear that dealing with oversupply is a key function of the auction reserve price mechanism.

D-13. Comment: The Utilities request the following addition to clarify the allowance price for 2016 future allowance prices. Modify section 95911(b)(6)(A) as follows:

(A) For auctions conducted in calendar year 2012 and 2013 the Reserve Price shall be $10 per metric ton for CO_2e for vintage ~~2012~~2013 allowance. For auctions conducted in 2012, the Reserve Price shall be ~~and $11.58~~ $10 per metric ton of CO_2e for vintage 2015 allowances. For auctions conducted in 2013, the Reserve Price shall be $10 per metric ton of CO_2e for vintage 2016 allowances. (MID3)

Response: We disagree that the language is not clear and did not make the change. All auctions in 2012 and 2013 will use the base $10 auction reserve price.

Auction

Auction General

D-14. Comment: Section 95910(a)(1) states that the first auction will be held on August 15, 2012. This date is before these rules will be considered by the CARB Board. (SCAQMD4)

Response: The cap and trade regulation was adopted by the Board on October 20, 2011, and will become effective before the first auction date.

D-15. Comment: Section 95910(c)(2) designates the auction of allowances from future budget years. The Utilities are concerned that this section is somewhat ambiguous and request clarification particularly as to the early auction of 2014 allowances. The RPR indicates that in 2012 allowances from the 2015 budget will be auctioned, and in 2013 allowances from the 2016 budget will be auctioned, and so forth. It does not address the future auction of any allowances from the 2014 budget. The Utilities suggest it may be helpful for CARB to provide a matrix of what allowances are going into each auction and at what reserve price. (MID3)

Response: Section 95910(c)(2) does not explain the advance auction of 2014 allowances because vintage 2014 will never be part of the advance auction. The first vintage to be sold at the advance auction will be 2015. All auctions in 2012 and 2013 will use the base $10 auction reserve price.

D-16. Comment: Section 95910(c)(2)(A) states that at each auction in 2012, one-half of the allowances designated for advance auction will be from the 2015 budget. It was our understanding that program participants could consign their own allowances for auction. If so, then what happens if they consign allowances from future years in a way that prevents one-half of them from coming from year 2015? (SCAQMD4)

Response: Entities may only consign allowances from the allowances they receive through direct allocation, which does not include future vintage allowances.

D-17. Comment: We support ARB's proposal to make one third of vintage 2013 allowances available to entities in 2012 through two auctions scheduled in August and November. Following ARB's decision to begin enforcement of the program in 2013, we agree with staff that there is still opportunity and value to the program to begin auctioning of allowances in 2012. Holding an auction for the electric utility sector in August 2012, as proposed, will reinforce confidence in the market that the program will continue as planned and help facilitate early price discovery. In addition, the proceeding underway at the California Public Utilities Commission (CPUC) will ensure that the electric utilities have the authorization they need in time to begin collecting costs and distributing revenues from the sale of emission allowances. (KUSTIN16)

> **Response:** No response is needed.

D-18. Comment: It is necessary to clarify that it is CARB and the Executive Director that have the authority to move allowances out of the Limited Use Holding accounts for the consignment auctions. Modify section 95910, 95910(d)(4)(A) and (B) as follows:

> Section 95910. ~~Timing Of~~ Auction Of California GHG Allowances.
>
> (A) For the auctions conducted in 2012, allowances designated for consignment pursuant to section 95892(c) must be transferred by the Executive Director to the Auction Holding Account at least 10 days before each auction.
>
> (B) Beginning in 2013, allowances consigned to auction through a transfer by the Executive Director to the Auction Holding Account at least 75 days prior to the regular quarterly auction will be offered for sale at that auction. (MID3)
>
> **Response:** Section 95910(d)(1) states that an entity may consign allowances to the Executive Officer for sale at auctions. The consignment is the request made by the entity to the Executive Officer, which according to section 95910(d)(4)(A) must be completed within 10 days of auction. We believe these provisions are sufficient to give the Executive Officer authority to transfer the allowances as needed. There is no need to make the change recommended in the comment.

D-19. Comment: PG&E believes that ARB adjusted the consignment requirement to 75 days prior to auction in order to allow ARB to process information and publically release auction information 60 days before the auction. However, PG&E recommends that the consignment requirement be 65 days before each auction starting in 2013 as we believe this 5-day window provides ARB sufficient time to sum allowance quantities from the consigning entities and publish auction information sixty days prior to auction. Modify section 95910(d)(4)(B) as follows:

> (B) Beginning in 2013, Allowances consigned to auction through a transfer to the Auction Holding Account at least 65 days prior to the regular quarterly auction will be offered for sale at that auction. (PGE4)

Response: We proposed the 75-day time period not only to allow us to complete the necessary administrative tasks but also to give auction participants time to adjust their auction purchase strategies to the level of consignment. If we did not add this provision, the consigning entities would have an advantage over other auction participants in having some advance knowledge of the level of consignment. Auction participants would know the number of allowances that will be consigned during the year, but not the timing. We believe they need the longer time limit to revise their purchase strategies once we publish the number of allowances consigned, since they could not have anticipated the actual number of allowances being offered for sale.

Auction Frequency

D-20. (multiple comments)
Comment: The modified program rules provides for a quarterly auction schedule, which is inconsistent with the most recent research and analysis conducted in connection with the management of carbon market auctions in Europe. Based on this research and recent market experience, the European Union now requires that, starting in 2013, all auctions be conducted on a weekly basis or more frequently. The concern with infrequent auctions (including quarterly auctions) is that they may result in price volatility and price spikes when the auctions are held and provide more opportunities for the exercise of market power between each such auction. More frequent auctions provide better price signals and help smooth price volatility. As an alternative to the purchase limits and position limits, IETA recommends that ARB consider conducting auctions more frequently, including for example on a monthly basis. (IETA3)

Comment: Research conducted by Linklaters indicates that the most efficient way to address the risk of market manipulation is to hold auctions frequently. More auctions reduce the risk of market abuse because of the decreased value at stake in smaller auctions. They also minimize price volatility experienced at the time of allowances auctions and the risk of any market player exercising market power between auctions. For those reasons, most agencies managing carbon markets have moved to a weekly auction schedule, including in Europe and Germany where, by law starting in 2013, auctions must be held on a weekly basis or more frequently. RGGI is an outlier whose design dates back to 2006/2007. The RGGI quarterly auction schedule, however, has been largely untested because the RGGI market is long and trading activity is low, which materially diminish the incentives for any players to manipulate the markets. If ARB is concerned about the potential for market abuse that may arise from modifications to the auction purchase limit and/or the holding limit, it can adopt the approach used in most carbon markets for fighting market abuse and increase the frequency of auctions. (CHEVRON3)

Comment: The Cap and Trade Regulation currently provides for quarterly auctions for allowances for each of the compliance periods. This frequency does not reflect the most recent research and analysis conducted in connection with the management of carbon market auctions in Europe. Based on the most recent data, the European Union now requires that, starting in 2013, all auctions be conducted on a weekly basis or more frequently. The concern with infrequent auctions (including quarterly and monthly auctions) is that they provide more opportunities for speculators and financial intermediaries to manipulate markets between the auctions. Another concern is that infrequent auctions increase price volatility and can result in price spikes around the time auctions, which result in market inefficiencies. More frequent auctions provide better price signals and help smooth price volatility, which are crucial elements for long-term planning purposes. Although RGGI has a quarterly auction schedule, this design feature essentially dates back to 2006 and does not build upon recent experience with carbon markets. Furthermore, the RGGI market design has not been fully tested because the market is long, activity is slow and prices are low. Accordingly, the WSPA members do not believe RGGI is a useful or realistic precedent in this respect for the California market. For example, in the EU ETS phase 2, the UK had larger, less frequent auctions (6-8 per year), where market volatility was directly attributable to the auctions. On the other hand, Germany had weekly, smaller auctions, and the market largely absorbed the volume without noticeable price impacts. Increase auction frequency to monthly to both address issues of market volatility and reduce the opportunity for market manipulation due to the predictability of compliance entities to use each auction so that they can cost optimize due the holding limits. Modify section 95910(a) as follows:

(1) In 2012, auctions will be held on August 15 and monthly thereafter on the 15th of every month.
(2) Beginning in 2013, auctions shall be conducted on the 12th business day of every month throughout the end of the program in December 2010. (WSPA3)

Response: We disagree with several unsupported assertions made in the comments. First, a quarterly auction does not necessarily provide more opportunities for speculators to manipulate the market. Covered entities that purchase allowances to match recent emissions or forecast emissions between auctions will simply purchase a larger amount at each auction. A change in auction frequency may change volumes purchased at each auction, but they do not change the purchasing strategy used by covered entities. They do not have to purchase on the secondary market between auctions.

Second, infrequent auctions do not cause increased variability or price spikes. These originate from changing assessments of supply and demand conditions. We do agree that under certain assumptions of how covered entities behave that increased auction frequency could help the market adjust to external shocks. There is also great value to auction participants in having the purchases of non-covered entities be spread out over several auctions.

We are aware of new program developments in the EU, although the attribution of the level of market price volatility solely to auction frequency is too speculative. We will be following the EU experience closely to help us determine the value of more frequent auctions.

We did not choose a quarterly format only because RGGI operates with that format. Our stakeholder consultations held in 2009 and 2010 brought up other factors affecting our decision. First, stakeholders did believe the quarterly format was operating successfully at the time. Second, both stakeholders and staff were concerned with the ability of all covered entities to participate in frequent auctions due to the costs and time commitments. Some California covered entities have extensive experience with auctions and commodity markets and have resources to conduct extensive auction and secondary carbon market participation; others do not. We believe retaining the quarterly format will give covered entities time to develop the capabilities for more frequent auction participation. Third, we have not operated auctions or financial activities on this scale before and must develop the contract services, internal procedures, and enforcement mechanisms needed for successful implementation. We note that the EU ETS auctions are generally conducted by national ministries with extensive experience in market operations. Auctions pose no great institutional challenges for them.

We concluded that the quarterly format can be successfully implemented without damaging the market. At the same time, we do see some value in moving to a more frequent auction once we develop the institutional capability, stakeholders develop familiarity with the process, and we can review a longer period of market information from the EU ETS. We could then change the auction schedule through another rulemaking, if needed.

Auction Purchase Limit

D-21. (multiple comments)
Comment: Providing an exception to purchase limits solely for electrical distribution utilities (section 95911(c)(4)(B)) is not supportable. This potentially provides an unfair competitive advantage over independent generators, and creates two cost tiers between IOUs and any and all other compliance entities. Such a market design is simply not equitable. It would be best not to have discriminatory purchase limits among classes of market participants at all. Somewhat less inequitable would be to design a limit that is the higher of the “generic” limit, or some quantity related to an entity’s reasonably expected compliance obligation. MSCG strongly recommends removal of part B. Alternatively, design a non-discriminatory set of limits that does not have disparate treatment of one class of market participant relative to others. (MSCG3)

Comment: The purchase limit on allowances discriminates against independent power producers (IPPs) in favor of Utility Owned Generation (UOGs). The purchase limit should be modified to reflect individual Covered Entities compliance obligations. The utilities’ exemption from the purchase limit should be deleted, section 95911(c)(4)(B). In addition, section 95911(c)(4)(A) should be modified to set a large covered entities purchase limit based on its compliance obligation. Modify section 95911(c)(4) as follows:

(4) For the auction of current vintage allowances:

(A) The purchase limit for covered entities and opt-in covered entities will be 10 percent of the allowances offered for auction. Upon an application by a covered entity, CARB may determine that the established Purchase Limit disadvantages the covered entity unreasonably, and CARB may establish a unique purchase limit for the covered entity scaled to the appropriate magnitude of the covered entity's compliance obligation.

(B) ~~The purchase limit does not apply to electrical distribution utilities receiving a direct allocation of allowances pursuant to section 95892(b) and subject to the monetization requirement pursuant to section 95892(c). This provision shall not be interpreted to exempt said electrical distribution utilities from any other requirements of this article; and~~ The purchase limit for all other auction participants is four percent of the allowances offered for auction. (IEPA2)

Response: We added the exclusion to deal with the imposition of a requirement that the electrical distribution utilities be required to consign their entire direct allocation of allowances to auction rather than use them for their compliance needs, as other recipients of direct allocations are allowed. We set the purchase limits reflecting the ability of other covered entities to use their direct allocations for their own compliance. Thus, the provision remedies a provision that would otherwise place utilities in a non-competitive position. Given the consignment requirement, and the need for utilities to purchase above their direct emissions in order to cover emissions from long-term contracts, the exemption from the purchase limit does not give the utilities an advantage over other covered entities or create an inequity as the comment suggests.

D-22. Comment: We oppose proposals to relax an individual entities' purchase limit should allowances remain unsold at auction. As ARB has designed the program, unsold allowances should fill the reserve to provide a cost containment function that is accessible to all parties. Allowing certain firms to bet on future shortfalls by stockpiling allowances at an auction invites the sort of market speculation and manipulation that can undermine confidence in the program and inhibit performance of the market. (KUSTIN16)

Response: We did not propose to relax the purchase limit in case an auction results in unsold allowances. Instead, unsold allowances will be returned to later auction after two auctions reach a settlement price above the auction reserve price. At that point, all auction participants will have an equal opportunity to bid on the allowances.

D-23. Comment: ARB has increased the auction purchase limits for allowances of future vintage years but did not change the policy on the purchase limits applicable to current vintage years and the position on holding limits. The primary concern with the purchase limit contained in the Regulations is that the limit is set below the compliance requirements of certain large covered entities. ARB's proposal that covered entities cannot purchase in an auction, or hold in their account, a sufficient quantity of allowances to meet their legal obligations is without basis. ARB has essentially designed its market to guarantee that large entities will be short in every auction and required to go into the secondary market to buy their allowances at a premium from speculators and financial intermediaries. This is a fundamental market flaw that provides an opportunity for such players to corner the market and, as such, it is unacceptable, especially in light of the State's experience with energy markets. Chevron has included expert analysis from the international law firm Linklaters LLP which is recognized worldwide for its expertise with commodities and carbon markets. According to research conducted by Linklaters, no other major current commodities or carbon market contains position limits such as those included in the proposal.

The proposal's position limit is actually a rule developed by the Commodities Futures Trading Commission (CFTC) to regulate futures commodities markets for the purpose of minimizing financial exposure of market participants. The CFTC rule is not intended to curb the risk of market manipulation and its extension to spot (or inventory) markets for this purpose is untested and not supported by empirical data and proper analysis. Similarly, Linklaters has indicated that no other carbon market contains purchase limits similar to those included in the proposal, except for the Regional Greenhouse Gas Initiative (RGGI). In RGGI, however, the purchase limit is 25 percent, not 10 percent, and no covered entity's compliance obligation in RGGI exceeds that 25 percent purchase limit. To address this issue, ARB does not need to remove the proposed purchase limits or position limits. The simple fix is to permit covered entities to bid and hold a quantity of allowances up to the limit contained in the current proposal, or a quantity equal to that covered entity's compliance obligation (at a minimum), whichever is greater. (CHEVRON3)

> **Response:** First, the commenter is not correct in its assertion that the holding limit was developed by the CFTC to regulate futures markets. The holding limit was developed in consultation with Jeffrey Harris, who was formerly employed at the CFTC. His recommendations were specific to the carbon market being developed by California and the other WCI jurisdictions.
>
> Second, consideration of position and purchase limits is not unprecedented. The EU ETS members have identified position and purchase limits as backstops that could be introduced as needed in case anti-competitive conditions emerge. The commenter is correct in that the three national programs reviewed (France, the UK, and Germany) and EU ETS did not select fixed purchase and holding limits as did California. However, the review of these programs contained in the comment shows that the programs did consider the fixed limits to be valid, but preferred to use them as a last resort. Instead, they chose a method they considered superior: imposing a bid limit if the size of a bid poses a risk of anti-competitive behavior. This is similar to the use of "responsibility levels" or variable position limits in U.S. commodity markets. However, we do not have the

authority to use such approaches because they require a level of discretion in their application that we do not have under the Administrative Procedure Act that governs our rulemaking. In addition, we understand that the EU ETS members also are considering, and have the authority to impose, purchase limits after the program has begun operation if problems arise. If we did not include such limits in the current regulation, we would have to undertake a new regulation. This would not be a quick process, so it is clear that we do not have the flexibility that the EU ETS members have in keeping purchase limits in reserve.

We do not consider the RGGI example to be relevant to our market. Our cap decreases immediately, and we anticipate that there will not be a large supply of compliance instruments that are not committed to covering compliance obligations due in 2015. The RGGI market did not take this approach, with the result that the market has built up a cushion of allowances in circulation that make manipulations difficult and reduce the need for strict purchase limits.

Third, all registered entities can keep in their holding accounts up to about 6 million MT of allowances in the first compliance period and about 11 million MT in the second compliance period, all of which will be available for trading. The comment does not explain why this is not sufficient to provide market liquidity or for covered entities to meet their obligations. In addition, we set the revised purchase limit to 15 percent to reflect the emissions of the largest emitters, net of the direct allocation they receive from ARB.

D-24. Comment: The modified regulation's 10 percent auction purchase limit disadvantages entities with large compliance obligations. While entities with small compliance obligations may be able to procure all their compliance needs for a year in a single auction, entities with larger compliance obligations would not. We see no compelling need for a purchase limit and would prefer that it be eliminated. If ARB retains the purchase limit, we recommend raising it to 25 percent for all market participants, including IOUs. This limit is consistent with that used in the Regional Greenhouse Gas Initiative. Modify section 95911(c)(4) as follows:

(4) For the auction of current vintage allowances:

(A) The purchase limit for covered entities and opt-in covered entities will be ~~10~~ <u>25</u> percent of the allowances offered for auction; <u>and</u>

~~(B) The purchase limit does not apply to electrical distribution utilities receiving a direct allocation of allowances pursuant to section 95892(b) and subject to the monetization requirement pursuant to section 95892(c). This provision shall not be interpreted to exempt said electrical distribution utilities from any other requirements of this article; and~~

(~~C~~<u>B</u>) The purchase limit for all other auction participants is four percent of the allowances offered for auction. (WPTF2)

Response: The statement in the comment that large entities cannot obtain sufficient allowances to cover their emissions is not correct. Covered entities will need to purchase at auction a number of allowances equal to their direct emissions, less the direct allocation they receive from us. We increased the purchase limit to 15 percent and believe that this limit is large enough to allow covered entities to purchase their net allowance needs at auction. This means covered entities would not need to purchase on the secondary market. The rationale for the limits themselves is included in the responses to the 45-day comments.

D-25. Comment: The proposed regulation's 10 percent purchase limit needs to be increased to accommodate the size of large independent generators such as Calpine, which may realistically need to purchase more than 10 percent of the available allowances in any auction to meet their compliance obligation. Calpine recommends that the auction purchase limit for covered entities during the first compliance period generally be kept at 10 percent of the total number of allowances available any given auction, but with an opportunity for any covered entity or group of covered entities with a corporate association to exceed this limit, so long as its total purchase of allowances of any vintage year does not exceed 125 percent of its average annual verified emissions during the preceding three calendar years, plus, for any entity with less than three years' reported emissions data, an additional amount that represents a reasonable estimate of the entity's anticipated emissions during that calendar year. This would allow large affiliated entities, such as Calpine, to satisfy their anticipated compliance obligation through purchases at auction, while still avoiding the potential for covered entities to engage in market manipulation by purchasing an amount of allowances grossly in excess of their anticipated compliance obligations for any calendar year. As an alternative to the foregoing proposal, CARB could adopt a substantially higher auction purchase limit, such as the 25 percent limit applicable to Regional Greenhouse Gas Initiative (RGGI) states. Modify section 95911(c)(4)(A) and (B) as follows:

(A) The purchase limit for covered entities and opt-in covered entities will be 10 percent of the allowances offered for auction<u>, except for any covered entity or group of covered entities with a corporate association, which may purchase an amount of allowances in excess of 10 percent during any auction, so long as the total purchase of allowances of any vintage year does not exceed 125 percent of the entity's or group of entities' average annual verified emissions during the preceding three calendar years or, in the case of an electrical distribution utility acquiring allowances on behalf of second registered entity with whom it has established a beneficial holding relationship pursuant to section 95834(a)(2), 125 percent of the second entity's verified emissions during such three calendar years, plus, for any entity with less than three years' reported emissions data, an additional amount that represents a reasonable estimate of the entity's anticipated emissions during that calendar year; and</u>
(B) ~~The purchase limit does not apply to electrical distribution utilities receiving a direct allocation of allowances pursuant to section 95892(b) and subject to the monetization requirement pursuant to section 95892(c). This provision shall not be interpreted to exempt said electrical distribution utilities from any other requirements of this article; and~~ (CALPINE3)

Response: We raised the purchase limit to 15 percent and believe this change addresses the commenter's concerns. This reflects the emissions of the largest emitters, net of the direct allocation they receive from ARB.

D-26. Comment: PG&E does not support raising the 10 percent purchase limit in advanced auctions to 25 percent as described in section 95911(c)(3). The advanced auction purchase limit should be consistent with the other auctions. Such a high limit may lead to hoarding and increases the potential for market manipulation in the program. (PGE4)

Response: We set the purchase limit for the advance auction to 25 percent, higher than for the current vintage auction, for two reasons. First, in addition to giving a forward price signal, the advance auction allows larger entities that need to physically hedge future compliance needs without excessively tightening the supply of current vintage allowances. This is especially critical ahead of the expansion of program scope in 2015. Second, we imposed the purchase limits to help prevent some manipulative schemes that could be played, especially toward the end of a compliance period. These schemes cannot be played using allowances that cannot be used for compliance. Also, it should be noted that only 10 percent of any future vintage will be sold at advance auction. Thus, the purchase limit will prevent any entity from purchasing more than 2.5 percent of a vintage from the advance auction.

D-27. Comment: Auction Purchase Limits in section 95911(c) should be waived or increased in the event that allowances would otherwise go unsold in an auction. (CE2CC)

Response: We modified the regulation so that unsold allowances will be returned to auction after two consecutive auctions have reached an auction settlement price above the auction reserve price. They will no longer go to the Allowance Price Containment Reserve. We do not agree with the proposal in the comment to raise the purchase limit, since one of the objectives of the limit is to reduce the potential for concentration of holdings. We believe our proposal to return the unsold allowances to auction meets the objective of keeping the unsold allowances in the market, instead of taking them out of the market and placing them in the reserve.

D-28. (multiple comments)
Comment: Section 95911(c)(1) sets the purchase limits that any entity is allowed to purchase at each quarterly auction. WSPA believes that the auction purchase limit is unreasonably low that will inhibit longer-term planning. WSPA recommends that the purchase limits be deleted or significantly increased. (WSPA3)

Comment: ARB has increased the purchase limit for future vintage allowances for a single entity from 10 percent of the allowances offered per auction to 25 percent. The limit applicable to current vintage year allowance remains at 10 percent. This approach will prevent covered entities with compliance obligations in excess of the limits from purchasing a sufficient number of allowances at each auction that they need to comply with the law. The limitation is a market design flaw because it will create an artificial short on the large covered entities that could result in opportunities for other participants to exercise disproportionate market power. It also places such large covered entities at a competitive disadvantage vis-à-vis other covered entities with compliance obligations below the limit. IETA notes that no carbon market currently in operation contains a similar purchase limit, except for RGGI. In RGGI, however, the purchase limit is 25 percent and the largest covered entity requires less than 15 percent of the allowances under the cap to comply. In order to prevent this unintended effect, IETA recommends the auction purchase limits be revised to provide that all covered entities may purchase up to an amount equal to each individual entity's compliance obligation, plus the current proposed 4 percent limit granted to non-covered entities. This will ensure that all parties will be on a level playing field and avoid the result of creating a competitive disadvantage to some entities and not others. (IETA3)

> **Response:** We raised the purchase limit for covered entities in the first compliance period from 10 percent to 15 percent. We believe this will be sufficient for every covered entity to meet its compliance needs (net of direct allocation) from the auction.
>
> We are currently in discussions with other members of the WCI on both the holding and purchase limits. We expect that some revisions may be necessary, in part to recognize different regulations and laws in the different jurisdictions, and in part to recognize the different market structure that we face after linking. Any changes to the limits would be part of a separate rulemaking that links the programs, not this regulation.

D-29. (multiple comments)
Comment: While the Utilities are supportive of the changes to the Auction Purchase Limit, the Utilities are concerned that applying the purchase limit only to the first compliance period contradicts the intent of this provision. Modify section 95911(c)(2) as follows:

> ~~2) The auction purchase limit will apply to auctions conducted from January 1, 2012 through December 31, 2014~~. (MID3)

Comment: PG&E does not support the lack of Auction Purchase Limits in the second and third compliance periods as noted in section 95911(c)(2). PG&E believes Auction Purchase Limits should apply to all three compliance periods. Without sufficient Auction Purchase Limits, there is potential that market speculators have the ability to hoard allowance supply simultaneously driving up compliances prices and expediting the depletion of the APCR—both of which result in higher costs for electric distribution utility customers. Modify section 95911(c)(2) as follows:
(2) The auction purchase limit will apply to ~~auctions conducted from January~~

~~1, 2012, through December 31, 2014.~~ all auctions. (PGE4)

Response: Going forward, we expect that linking to WCI or to other ETS would also lead to changes in the purchase limit. Since these linking arrangements would take the form of new regulations with new purchase limits, we concluded that setting a purchase limit now to last through 2020 would be misleading.

D-30. Comment: Linklaters' review of the regulations governing major carbon and commodities markets in the countries identified demonstrates that the holding limit included in the Regulations is unprecedented. In proposing the holding limit, ARB has taken a rule designed by the CFTC to prevent systemic risk in the futures market and has applied it to an Inventory Carbon Market. The purpose of the rule was not to curb potential market power issues, but rather to protect the market from systemic risk that arises where any one market participant takes on too large a position. In proposing the holding limit ARB has taken a rule designed by the CFTC to prevent systemic risk in the futures market and has applied it to an inventory carbon market. We are aware of no date, information, or research that demonstrates or otherwise purports to show precisely what positive impact the holding limit rule will have on the inventory carbon market. (CHEVRON3)

Response: The comment is correct in that the three national programs reviewed (France, the UK, Germany) and EU ETS did not select fixed purchase and holding limits as did California. However, the review mentioned in the comment shows that the programs did consider the fixed limits to be valid, but preferred to use them as a last resort. Instead, they chose a method they considered superior: imposing a bid limit if the size of a bid poses a risk of anti-competitive behavior. This is similar to the use of "responsibility levels" or variable position limits in U.S. commodity markets. However, we do not have the authority to use such approaches because they require a level of discretion in their application that we do not have under the Administrative Procedure Act that governs our rulemaking. In addition, we understand that the EU-ETS members also are considering, and have the authority, to impose purchase limits after the program has begun operation if problems arise. If we did not include such limits in the current regulation, we would have to undertake a new regulation. This would not be a quick process, so it is clear that we do not have the flexibility that the EU ETS members have in keeping purchase limits in reserve.

D-31. Comment: The holding limit will have unintended negative impacts. As currently drafted, the holding limit will result in lower market liquidity, because it will force covered entities with compliance obligations above the limit to take allowances out of the market by moving them into a compliance account. In a market where the underlying size is already low, this measure will exacerbate the ability of any participate to manipulate markets. (CHEVRON3)

Response: The comment is correct in that the largest entities will have to place a large share of their allowances in their compliance account under the limited exemption. However, we disagree with the commenter on two grounds. First, the comment overstates the impact on liquidity, because covered entities going short to take advantage of what appear to be profitable opportunities to sell instruments may end up losing money if an observed price increase turns out to be permanent. Second, the holding limit allows all entities to hold a large number of allowances that can be sold. In 2013, this limit will be about 6 million MT, and the limit rises to over 11 million MT in 2015. We believe that this amount is sufficient to give covered entities flexibility in market operations.

Auction Purchase Limit – Corporate Associations

D-32. Comment: NCPA supports the inclusion of provisions within the proposed regulation that ensure registered entities are not able to collude and adversely impact the allowance market and auction operations. Provisions regarding the disclosure of corporate associations and the imposition of auction purchase limits are necessary tools to meeting this objective. These restrictions, however, must be implemented in a manner that does not impede the regular business operations of entities such as JPAs that may have a compliance obligation under the program, yet be comprised of member utilities that also have their own compliance obligations. (NCPA3)

Response: We revised the level of control used to define when a direct or indirect corporate association exists, from 20 percent to 50 percent, using the measures defined in section 95833(a)(1). We also revised the procedures for handling of allowances that are directly allocated. These procedures make it easier for members of a JPA to ensure that allowances directly allocated to members of a JPA can be placed into the compliance accounts of the JPA itself without triggering any affiliation rules.

D-33. Comment: Existing language in section 95914(e)(2)(C) would allow a group of entities with a disclosable corporate association to purchase all allowances available at an auction rather than collectively limiting them to the auction purchase limit, contrary to section 95911(c)(1). Modify section 95914(e)(2)(C) as follows:

(C) Each associated entity's allocated purchase limit share times the auction purchase limit ~~number of allowances being auctioned~~ becomes the purchase limit for that entity. (SCAQMD4)

Response: We agree and made the appropriate change.

D-34. Comment: Corporate Association Consolidation - Liquidity is critical to market functionality and to cost containment. The proposed rule includes position holding limits and purchase limits that apply to companies and any indirectly affiliated entities. This policy effectively punishes the larger companies for having expanded their investments in California without controlling interests. This policy would also compromise fair competition by requiring that companies communicate their trading and holding positions to third parties who have a competitive interest in the market. At a minimum, the exception in Section 95920(f) of the proposal should be applied to the purchase limit in Section 95911. (CHEVRON3)

> **Response:** We removed section 95920(f) and replaced it with new section 95833(a)(4) so that the exception applies to all instances where corporate association rules come into play, not just in the holding limit as pointed out by the commenter. The intent of a number of revisions to section 95833 is to ensure that we are applying corporate association rules to instances where control occurs.

D-35. Comment: WSPA understands the need for disclosure of direct and indirect corporate contacts in order for the cap and trade system to be transparent and to allow ARB to monitor for market manipulation. The problematic issue is the conditions that attach to the activities of direct and indirect corporate entities. For example, section 95911(c) limits the number of compliance instruments that can be bought at any specific auction by an entity or a “group of entities with a disclosable corporate association.” These limits are set at 25 percent of the future vintage compliance instrument and 10 percent of the current vintage compliance instruments that are available at any given auction. Section 95920 also limits the number of compliance instruments that can be held by an entity or group of entities with a disclosable corporate association. These two limits create significant legal and pragmatic compliance difficulties for joint ventures, partnerships, and limited liability companies. For instance, in order to determine compliance with these requirements, the equity owners of these joint business relationships would be required to disclose their bidding strategy and compliance instrument ownership positions to each other. This problem is further exacerbated when the two or more equity owners are competitors in either the same or other industrial sectors. Such disclosures may be prohibited by both state and federal antitrust laws and regulations. In addition, the two or more equity owners may also hold disclosable corporate associations with numerous other unrelated joint venture, partnerships or limited liability companies, thus creating an extremely complex web of inter-company communications and reporting requirements which are pragmatically and legally difficult or even legally infeasible. We note that in 95833(a)(4) there is an exception that does not require entities to take “other action” that violates “other rules”. The section does not provide any guidance on what the entities must do or provide in these cases. Rather than providing a pathway for compliance, it adds additional uncertainty and compliance exposure. WSPA supports the disclosure requirements of section 95833 that give ARB or the market administrator the opportunity to monitor these direct and indirect corporate associations for inappropriate activity. WSPA recommends the auction and holding account limits apply only to the specific joint venture, partnership or limited liability company and not be applied to entire group of associated corporate entities and their own unassociated disclosable business entities. (WSPA3)

> **Response:** We agree with the concerns expressed in the comment. However, we believe the modification to section 95833(a)(4) addresses these concerns. In addition, in the second 15-day Change Notice, ARB raised the requirements

determining when an entity has control over another. The specific measures of control listed in 95833(1) now must show a level of control of 50 percent or greater, up from 20 percent. If control is not established, there is no need for disclosures that could involve state or federal prohibitions.

Auction Administration and Registration

D-36. Comment: PG&E still seeks additional detail in the Regulation on auction design including credit management process, default management process, definition of security and rating requirements, credit terms, revenue shortfall allocation, and settlements. (PGE4)

> **Response:** The regulation sets out the rules that registered entities must follow, which in this case includes the bid guarantee and information submission for auction and Reserve sale participation. Generally, administrative processes such as the ones listed are not included in the regulation beyond the specification of the rules themselves.

D-37. Comment: Section 95912(c) contains language that is redundant to the new language in section 95912(c)(2) which provides that "an entity will be required to complete an auction registration application at least 30 days prior to an auction in which it intends to participate." This latter expression is more precise. Modify section 95912(c) as follows:

> (c) Auction Registration Requirements. ~~An entity that intends to participate in the auction must complete an auction registration at least thirty~~ 30 ~~days prior to the auction.~~ (MID3)

> **Response:** Section 95912(c)(2) is not redundant because it lists the information that an entity must provide when applying to participate in an auction.

D-38. Comment: Regarding sections 95912(c)(2)(D) and 95912(b)(3), the standards for approving an auction registration should be defined explicitly, including the criteria for consideration of "any previous or pending investigation with respect to any alleged violation of any rule, regulation, or law associated with any commodity market or exchange" in the decision to approve or deny. (SCAQMD4)

> **Response:** The information disclosure requirements in section 95912(c) are designed to aid us in market surveillance efforts, including those to determine whether an entity is under investigation for behavior in related markets. The information will aid us in detecting manipulative schemes that involve transactions in related markets, such as our cap-and-trade market and carbon futures markets, for example. Section 95914(c) contains the rules governing whether the Executive Officer will accept a registration.

D-39. Comment: PG&E is concerned about the burden to satisfy requirements in section 95912(c)(2). As written, the requirement seems too broad, particularly, section 95912(c)(2)(D), which states that "The identification of any previous or pending investigation with respect to any alleged violation of any rule, regulation, or law associated with any commodity market or exchange." PG&E seeks clarity on the requirements, since market participants are already required to disclose any Beneficial Holding relationships as part of their registration application and subsequent updates, the requirement appears redundant. (PGE4)

> **Response:** The information disclosure requirements in section 95912(c) are designed to aid us in market surveillance efforts, including those to determine whether an entity is under investigation for behavior in related markets. The information will aid us in detecting manipulative schemes that involve transactions in related markets, such as our cap-and-trade market and carbon futures markets, for example. There is no connection between this disclosure requirement and the beneficial holdings requirement. Section 95914(c) contains the rules governing whether the Executive Officer will accept a registration, which focus more on provision of false information as a reason for rejection.

D-40. Comment: PG&E recommends that section 95912(c)(2)(E) be modified to be consistent with section 95912(k)(3) which describes the transfer of allowances to winning bidders' Holding Account or Compliance Account. Modify section 95912(c)(2)(E) as follows:

> (E) The applicant's holding account number <u>and compliance account number</u>. (PGE4)

> **Response:** An entity's compliance account is tied to its holding account. Disclosure of a holding account number is sufficient to allow the Executive Officer to complete the activities in section 95912(k)(3).

D-41. (multiple comments)
Comment: PG&E recommends that the Executive Officer notify the entity within five days whether its application is approved (section 95912(c)(3). (PGE4)

Comment: Section 95912(c)(3) requires EO approval of an entity's registration before an entity may participate in an auction. However, there is no timeline for EO approval. WSPA recommends that the regulation require the EO to approve or deny a registration within 10 days of the completed registration submittal by any entity. (WSPA3)

Comment: The following additional language is needed to ensure that an entity having a compliance obligation is not precluded from participating in an auction due to delays in CARB's processing of a timely registration request. Modify section 95912(c)(3) as follows:

(3) The Executive Officer must approve an entity's auction registration before that entity may participate in an auction; provided that if the entity submits an auction registration as set forth in 95912(c)(2) the Executive Officer shall act on the registration prior to the auction. (MID3)

Response: The time needed for approval will depend on the number of applications received. In addition, the processing time for a first-time application would be higher than for a renewal. At the start of the program, we expect to process a large number of applications, as all covered entities will most likely apply to participate in the first auction. After that, the processing time should decrease due to the provision that entities may retain their auction registration through compliance with program rules. They would only be required to update the information disclosed. Given that we expect processing time to decrease dramatically after the program begins, and that we see no benefit to placing a limit on processing time, we did not make the recommended change.

D-42. Comment: Regarding section 95912(d)(2), has consideration been given to an exemption for the case of a change occurring less than thirty days prior to an auction? Without such an exemption, there is the possibility that an unavoidable change occurring at an inopportune time could result in a compliance problem for a covered entity or opt-in covered entity. Modify section 95912(d)(2) as follows:

(2) An entity approved for auction participation must inform the auction operator at least 30 days prior to an auction when reporting a change to the information disclosed or no more than two days after the change occurs, whichever is later, otherwise the entity may not participate in that auction. (SCAQMD4)

Response: We included the requirement to ensure that we have the information needed to analyze the bids and make the determinations that bids conform with rules. These include bid guarantees, purchase limits, and holding limits (section 95912(j)), as well as certification of the auction itself (section 95912(k)(1)). The information in the application includes identifications of corporate associations, beneficial holdings, and pending legal investigations. We need time to check this information for consistency against other sources and then make a large number of calculations for rules such as holding and purchase limits. We cannot accept the suggested timeline because we would not have enough time to perform the necessary work. In addition, the timeline may compromise the ability of our contracted market monitor to prepare for its assessment of conduct of the auction.

D-43. (multiple comments)
Comment: Section 95912(e) prohibits a registered entity from communicating "information on auction participation" with any other entity. This appears to be quite broad. We suggest identifying what kind of information may not be communicated, and specifying that information may be communicated to an entity authorized to obtain such information for law enforcement purposes. For example, a District Attorney may be

investigating possible collusion of fraud. (SCAQMD4)

Comment: Section 95912(e) contains restrictions on the communication of information on auction participation that do not work as currently written for electric distribution utilities that are regulated by the CPUC due to the current language forbidding those entities from sharing auction participant information with their respective regulators and Procurement Review Groups. Modify section 95912(e) as follows:

> (e) A registered entity may not communicate information on auction participation with any other entity that is not part of an association disclosed pursuant to section 95914, except as requested by the auction operator to remediate an auction application <u>or for a registered entity to consult with its regulators or any group authorized pursuant to regulatory order to review procurement activities.</u> (PGE4)

> **Response:** We did not make the suggested change to section 95912(e) because we believe other changes to the regulation (specifically section 95833(a)(4)) satisfies the commenter's concern. We modified section 95833(a)(4) at the request of electrical utilities. The modified language makes clear that we are not adding any rules that contradict state or federal rules governing the conduct of regulated entities.

D-44. Comment: Deadlines should be established for ARB decision-making processes to provide entities with a degree of certainty. Modify section 95912(k) as follows:

> (k) Following the auction, the Executive Officer will:
>> (1) Certify whether the auction was operated pursuant to this article <u>within 5 days</u>;
>> (2) After certification, <u>immediately</u> direct the auction operator financial services administrator to: (CCEEB3)

> **Response:** We cannot make the change suggested in the comment because we cannot accept a restriction on our ability to investigate potential market manipulation or other misconduct. We do not believe that preempting such investigation with an arbitrary deadline would provide auction participants with greater certainty.

D-45. Comment: In section 95914 we are not sure if there is any provision for appeal of the EO's decision to exclude violating participants from future auctions. Perhaps the Executive Officer's discretion can be limited so it will not be arbitrarily executed by defining what punishment is proportional to the violation. (SCAQMD4)

> **Response:** Section 95914 sets forth actions the Executive Officer may take in

response to violations. We have a process for addressing violations. The process can include discussions with the alleged violator. We did not make the change suggested because we have demonstrated through years of enforcement how our procedure operates.

D-46. Comment: Regarding section 95914(d)(4), the intent of the phrase "to entities that are not subject to exclusion pursuant to section 95914(d)(1)" is unclear because section 95914(d)(1) identifies information that entities approved for action participation may not disclose but does not identify any entities that are or are not subject to exclusion. Any exceptions to the disclosure prohibitions of section 95914(d)(1) should be explicitly stated. (SCAQMD4)

Response: Entities excluded from the disclosure rules in section 95914(d)(1) include auction participants qualifying pursuant to section 95914(d)(2) and (3). These two sections describe allowable information sharing. In addition, information sharing prohibitions, along with any of provisions dealing with associations among entities, are subject to the general exclusion contained in section 95833(a)(4). We believe these exclusions are clear.

D-47. Comment: The Utilities suggest the following minor clarification to ensure that the threshold for triggering the application of this article is not unreasonably set too low. Modify section 95914(c) as follows:

(c) If the Executive Officer determines that a bidder has intentionally provided false or misleading information, or has withheld material information in its application, or has violated any part of the auction rules set forth in subarticle 10, then: (MID3)

Response: Section 95914 sets forth actions that the Executive Officer may take in response to violations. We have a process for addressing violations. The process can include discussions with the alleged violator. We did not make the change suggested because we have demonstrated through years of enforcement how our procedure operates. In addition, the requirement to prove intent is rarely achievable. Imposing it would limit our ability to deal with many legitimate violations.

D-48. Comment: MSCG recommends that the prohibition against disclosing Qualification status (section 95914(d)(1)(A)) be eliminated. It is unclear to MSCG what the potential harm to the market may be from simply revealing that a company has qualified to bid in the auction. It is normal business practice in many circumstances to simply represent to potential clients and/or customers that MSCG is qualified, and is an eligible market participant, as a way to promote our capabilities when soliciting business. For this reason, we recommend that the prohibition on revealing qualification status be eliminated. (MSCG3)

Response: Sections 95914(d)(2) and (3) describe cases in which information can be shared. We believe that these cases would address the concern of how the disclosure rules in section 95914(d)(1) could affect the commenter's business.

Outside Scope of 15-Day Changes

D-49. Comment: The following revision is necessary to maintain internal consistency within section 95911(d). Section 95911(d)(5) describes only procedures for where the quantity of allowances is "greater than." This is because if the number of allowances bid for is equal to the number of allowances available, then no resolution would be required.
Modify section 95911(d)(4)(B) as follows:

(B) The total quantity of allowances contained in the bids at the next lower bid price is greater than ~~or equal to~~ the number of allowances yet to be ~~awarded~~ sold… (MID3)

Response: We did not change the regulation based on the comments. As currently written, there is clarity in how sections 95911(d)(4)(B) and 95911(d)(5) relate to each other.

D-50. Comment: PG&E suggests that ARB add additional language to section 95911(d)(4) to ensure that each potential bid situation is addressed. Modify section 95911(d)(4) as follows:

(4) Beginning with the highest bid price, bids will be considered in declining order by price and entities submitting bids at that price will be sold allowances until either:

(A) The next lower bid price is less than the auction reserve price, or there are no additional bids, in which case the ~~current price~~ Reserve Price becomes the auction settlement price; or

(B) The total quantity of allowances contained in the bids at the next lower bid price is greater than or equal to the number of allowances yet to be sold, in which instance, the next lower bid price becomes the auction settlement price and the procedure for resolution of tie bids in section 95911(d)(5) shall apply. (PGE4)

Response: We did not change the regulation based on the comments. We believe that the current requirements adequately cover the potential situations that need to be addressed through regulatory text.

Bid Guarantee

D-51. (multiple comments)
Comment: The Regulation contains a requirement to provide the auction administrator with assurances in the form of bonding, cash, or a letter of credit. This requirement is really unnecessary and burdensome for compliance entities with large physical assets in the state and/or who may be investment-grade, credit-rated companies. Bid guarantees should allow demonstration of sufficient physical assets or investment-grade credit rating. (BP2)

Comment: WSPA notes that the Regulation contains a requirement to provide the auction administrator with assurances in the form of bonding, cash, or a letter of credit. This requirement is unnecessary and does not add certainty or improve the stability of the C/T program. This is especially ineffective and burdensome for entities with large physical assets in the state and/or who may be investment-grade, credit-rated companies. WSPA proposes that ARB should develop an open credit threshold on a sliding scale based on the published credit rating of the company. Some companies may have a published credit rating for the parent company that would need to be used for its sub companies. Modify sections 95912(h)(1)(E), 95913(e)(2)(E), and (F) as follows:

> <u>(E) Proof of publicly reported credit rating higher than ARB established credit threshold for auctions and allowance reserve bids.</u>
>
> <u>(F) Substantial asset base within the State.</u> (WSPA3)

Comment: Section 95912(h) requires that registrants of an auction provide a bid guarantee to the auction administrator at least one week prior to auction. The bid guarantee must be in one or a combination of the following forms: 1) a bond, 2) cash in the form of a wire transfer or certified funds, 3) an irrevocable letter of credit. Most municipal utilities carry bond covenants and restrictions that limit their ability to post assets as collateral, plus the cost for a letter of credit is significant. For electric distribution utilities, LADWP's preferred alternative to the ARB's bid guarantee requirements is to rely on a high bond rating as the basis for creditworthiness, such as "AA" or above to qualify an entity to participate in a quarterly auction. There are also creditworthiness provisions outlined in master agreements such as those available through the Western Systems Power Pool (WSPP) or Edison Electric Institute (EEI) that could be used as the basis for participation by utilities in a quarterly auction. ARB has tools available through enforcement and penalties for any default that might occur. Modify section 95912(h) as follows:

> (h) Registrants must provide a bid guarantee to the financial services administrator at least one week prior to the auction.
>
> > (1) The bid guarantee must be in one or a combination of the following forms:
> >
> > > (A) A bond issued by a financial institution with a United States banking license.

(B) Cash in the form of a wire transfer or certified funds, such as a bank check or cashier's check.
(C) An irrevocable letter of credit issued by a financial institution with a United States banking license; or
(D) If California participates in a joint auction with one or more Canadian Provinces pursuant to section 95912(b) then bonds or irrevocable letters of credit issued by a financial institution with a Canadian banking license will be acceptable.

(2) The amount of the bid guarantee must be greater than or equal to the sum of the value of the bids submitted by the auction participant.
<u>(3) A POU may submit documentation for its most recent high bond rating of "AA" or greater in lieu of a bid guarantee.</u> (LADWP4)

Comment: Minimize unnecessary bureaucratic requirements. Investment grade credit-rating should be permitted in lieu of bid guarantees in sections 95912(h) and 95913(e)(2). (CCEEB3)

Comment: PG&E continues to advocate that the bid guarantee requirements outlined in section 95912(h) be modified to consider auction sales for consigning entities in addition to bids. Modify section 95912(h)(2) as follows:

> (2) The amount of the bid guarantee must be greater than or equal to the sum of the value of the bids submitted by the auction participant<u> less the consignment quantity multiplied by the Reserve Price</u>. (PGE4)
>
> **Response:** These comments fall outside the scope of the first 15-day changes to the regulation. We responded to similar comments in the 45-day responses to comments. Inclusion of the bid guarantee in the language of sections 95912(h)(1) and (2) and section 95913(e)(2) did not change from the initially proposed regulatory language, and therefore was not subject to comment under the first 15-day changes to the regulation. Because the comments fall outside the scope of the notice, no further response is required.

Replenish Allowance Price Containment Reserve

D-52. (multiple comments)
Comment: CalChamber agrees that an allowance reserve is necessary, especially if intended as a cost-containment mechanism to moderate allowance prices. The allowance price reserve however is set too high. CARB is proposing to sell allowances through a Reserve Tier system where beginning 2013, allowances from the first tier will be sold at $40/metric ton, allowances from the second tier will be sold at $45/metric ton, and allowances from the third tier will be sold at $50/metric ton. The tier reserve system along with the escalating cost of the reserve throughout the compliance years negates

the overall purpose of the reserve, which is to serve as a cost-containment mechanism. We are concerned about the potentially high cost of allowances under this reserve system. We are also concerned about the manner in which CARB intends to fill the reserve by taking from the industry allowances. These are allowances that covered entities should receive freely in order to minimize economic leakage, but instead will be used to fill the price containment reserve at excessively high prices, negating the leakage issue and the overall point of a cost containment reserve. (CALCHAMBER3)

Comment: The Joint Utilities support the inclusion of the Allowance Price Containment Reserve (Reserve) in the Regulation as an essential tool to address the potential for higher-than-expected allowance prices. Because a robust Reserve is necessary to ensure long-term market success under a wide range of plausible scenarios, we believe CARB should establish a procedure in the Regulation to automatically replenish the Reserve if it becomes depleted. With language in the Regulation identifying the triggering event and action to be taken, the market will have assurance that a timely and effective remedy will be in place. (JOINTUTILITIES)

Comment: We offer these comments based on our experience in the California energy crisis and our desire to see a sustainable and successful Cap and Trade market that sets an example for others to follow. The market failure related to this crisis essentially defeated many of the goals of market deregulation, caused PG&E's bankruptcy, severe financial hardship for other utilities and adverse consequences for consumers and the California economy. Designing a Reserve that will successfully support this program under a wide range of scenarios greatly reduces the possibility that a cap and trade program will experience similar market failure, and defeat the important goals of AB 32. In part because of this experience, PG&E commissioned a study by Charles River Associates to assess the adequacy of the Reserve under a wide range of scenarios. The study concluded that either greater-than-expected economic growth or less-than-expected emissions reductions from program measures and offsets will result in a partial depletion of the Reserve. From this analysis, PG&E concludes that market failure, under certain conditions, is plausible. A robust Reserve is necessary to manage allowance prices and ensure long-term market success, and we believe the ARB should establish a procedure in the Cap and Trade Regulation to automatically replenish the reserve should it become depleted. We urge ARB to develop appropriate regulatory language that creates a process to replenish the reserve in the event 1/3 of the APCR allowances are sold. This process may include, but is not limited to an increase in availability of offsets for compliance purposes, temporary suspension of tracking and program compliance obligations, and adjustments to program allowance budgets. We offer these proposals in the spirit of ensuring the Cap and Trade market will be robust, will work for our customers, will provide additional emissions reductions at a fair price, will support the goals of AB 32, and will be an example for others to follow. (PGE4)

Comment: SCPPA thanks ARB for proposing the Allowance Price Containment Reserve (Reserve) to address the potential for higher than expected allowance prices. Because a robust allowance reserve is necessary to manage allowance prices and ensure long-term market success, the ARB should establish a procedure in the

Regulation to automatically replenish the reserve if it becomes depleted. With language in the Regulation identifying the triggering event and action to be taken, the market will have assurance that a timely remedy will be in place. SCPPA stands ready to work with ARB staff and concerned stakeholders to develop appropriate regulatory language that creates a process to replenish the reserve if it becomes depleted and provides for temporary suspension of the cap-and-trade market and related compliance obligations if the balance in the reserve drops to zero. The proposed language below is offered in the spirit of ensuring the Cap and Trade market will be robust, will work for our customers, will provide additional emissions reductions at a fair price, and will be an example for others to follow. Modify section 95913(c) as follows:

(c) Timing, Eligible Participants, ~~and~~ Limitations, <u>Reserve Replenishment and Market Stabilization.</u>

<u>(5) Replenishing the Reserve and Market Stabilization.</u>

<u>(A) When the Reserve is fully depleted, the Executive Officer shall make available for purchase by each Covered Entity sufficient allowances to allow that Covered Entity to fully satisfy any remaining compliance obligation. Only Covered Entities with a combined Holding Account and Compliance Account balance of zero shall be able to purchase such allowances. Such allowances shall be offered at the allowance price of the third tier of the Reserve at the time the Reserve contained 40 MMT or fewer allowances available for purchase. Purchases of such allowances shall be transferred directly into a Covered Entity's Compliance Account.</u>

(B) Whenever the Reserve is fully depleted, the Executive Officer and Market Monitoring Board shall report to the Board within 3 months. The report shall make recommendations to the Board on program modifications necessary to replenish the Reserve and to enable allowance prices in each quarterly allowance auction held pursuant to section 95910 to clear at or below the first tier of the Reserve. (SCPPA6)

Comment: SEu supports ARB's inclusion of the Allowance Price Containment Reserve (Reserve) in the Cap-and-Trade Regulation as an essential tool to address the potential for price spikes and a market meltdown that would overflow into electricity markets. Because a robust Reserve is necessary to ensure the long-term success of the Cap-and-Trade program, ARB should establish a procedure in the Cap-and-Trade regulation to replenish the reserve should it become depleted. With language in the regulation identifying the triggering event and action to be taken, the market will have assurance that a timely remedy will be in place. The approach outlined below is only one of several alternatives to accomplish the market stabilization goal, but would ensure the Cap-and-Trade market will provide additional emissions reductions at a fair price. Modify Section 95913(c) as follows:

Section 95913 (c) Timing, Eligible Participants, ~~and~~ Limitations, <u>and Reserve</u>

Replenishment.

(5) Reserve Replenishment.

(A) When the Reserve is fully depleted, the Executive Officer shall make available for purchase to each covered entity or opt-in covered entity sufficient allowances to allow that covered entity or opt-in covered entity to fully satisfy any remaining compliance obligation at the allowance price of the third tier of the Reserve at the time the Reserve is fully depleted.

(B) Only Covered Entities with a Holding Account balance of zero shall be able to purchase such allowances.

(C) Purchases of such allowances shall be transferred directly into a Covered Entity's Compliance Account.

(D) Within 3 months of the time the Reserve is fully depleted, the Executive Officer and Market Monitor shall make a recommendation to the Board on program modifications necessary to replenish the Reserve. (SEMPRA3)

Comment: ARB should specify in the regulation a method to replenish the APCR in the event that the reserve is stressed. With language in the regulation identifying the triggering event and action we will take, the market will have assurance that a timely remedy will be in place. Thus, ARB should specify a method to replenish the APCR in the event that 1/3 of the reserve allowances are sold. (PGE4)

Comment: ARB should outline a method for repopulating the Allowance Reserve in the event that it is stressed, or when at least one-third of the allowances in it are sold. As a mechanism to contain compliance costs, the Allowance Reserve can only be successful if there is sufficient supply of compliance instruments available for regulated entities. It is crucial that ARB have a method in place well before the Allowance Reserve approaches any level of stress, as efforts to evaluate the situation then will be too late to offer any resolution. (SCE3)

Comment: SCE recommends that the Allowance Reserve should offer a stable price ceiling in addition to the price floor. While the Allowance Reserve operates to provide allowances at a set price to regulated entities, unless there is a determined method to repopulate the Allowance Reserve, the market cannot be assured that there is any real long-term cost containment. (SCE3)

Response: The Reserve is not intended to completely eliminate the risk that allowance prices rise to unacceptably high levels as the commenter suggests. We have been clear that there is no "hard price cap" in the program. We rejected that approach as leading to interference with market price signals. We created the reserve to serve as a buffer against higher prices. The Board has directed staff to monitor depletion of the reserve and make recommendations for program revision as needed.

D-53. Comment: SMUD understands the desire, with a new market, to provide market certainty to those making determinations about whether to invest in a given reduction measure. We also understand that a floor price for allowances offered at auction is one way to ensure certainty, and that normal market discounting of future payoffs implies a need for an escalation of that floor price beyond normal inflation in immature markets. However, as markets mature, such investment signals will no longer be necessary. The 5 percent escalator in the proposed regulations will eventually result in excessive prices for allowances, in particular if carried beyond the 2020 timeframe. For a program with such strong complementary policies, the notion of forcing the floor price up to arbitrarily high levels seems punitive towards market participants who are trying to balance the high costs of complementary programs with the Cap and Trade costs. SMUD would recommend that ARB signal its intent to reflect maturing markets by tapering the 'above inflation' escalation off over time so that the escalation ends at no greater than the rate of inflation in the last year of the program. Modify section 95911(b)(6) as follows:

> (B) For auctions conducted in calendar years after 2013 the Reserve Prices shall be the Auction Reserve Prices for the previous calendar year increased annually by 5 percent plus the rate of inflation as measured by the Consumer Price Index for All Urban Consumers. <u>Beginning in 2016, the adjustment beyond the rate of inflation shall be reduced by 1 percent annually, leading to an increase in 2020 equal to the rate of inflation.</u> (SMUD3)

> **Response:** This comment falls outside the scope of the first 15-day changes to the regulation. We did not change the language specifying the method for determining the inflation rate of the Reserve Prices for auctions conducted in the calendar years after 2013 from the initially proposed regulatory language, and therefore it was not subject to public comment under the first 15-day changes to the regulation. No further response is required.

Auction Administration and Registration

D-54. (multiple comments)
Comment: ARB should notify market participants via e-mail if their bids were not accepted due to a violation of credit or holding purchase limit (section 95912(h)). (PGE4)

Comment: PG&E recommends ARB specify the timeline for which payments are collected and revenues distributed as described in section 95912(k). PG&E recommends that financial settlements occur by the end of the month in which the auction takes place. (PGE4)

> **Response**: We did not change the regulation based on the comments. Both of the comments are related to program implementation and do not have to be specified in the regulation.

Implementation: System-Testing, Tools, Training, and Forms

D-55. (multiple comments)
Comment: The Regulation contains detail in various sections regarding the availability of allowances for auction from various sources and at various times. It would be helpful to regulated parties and market participants for the Regulation to include a single table that shows very clearly for each year of the program: auction timing, source of allowances that will be auctioned, allowance vintage and number of allowances (even if approximate). (BP2)

Comment: PG&E supports ARB's decision to conduct two auctions in 2012 prior to the start of the compliance obligation. However, it is critical to test the robustness of the auction systems, design, and protocols through market simulations in the first half of 2012. Equally important is to test the auctions potential vulnerability to manipulation through "table top" and other market simulation exercises, with oversight by market auction experts. Through such testing, ARB would be able to identify possible weaknesses in the design and undertake remedies prior to commercial and financial commitments being made in the first two auctions in 2012. (PGE4)

Comment: PG&E has additional questions associated with the administration of the auction which are not addressed in the proposed regulatory language. These questions are listed below. If ARB opts to not include this type of detail in the Regulation, PG&E requests clarification regarding where this type of detail will be presented.

> 2. Per section 95912(g), "All bids shall be submitted to the Executive Officer and will be considered binding offers for the purchase of allowances under the rule of the auction." We request clarification on how the bids be submitted, the format of the bids, if there will be a template, and if it will be through a website. (PGE4)
>
> **Response:** These comments fall outside the scope of the first 15-day changes to the regulation. We have initiated activities to develop the necessary rule implementation infrastructure for the regulation, including contracts for an auction services provider, and a financial services provider. We are also committed to providing continual public updates, with opportunity for stakeholder comment, on the implementation of the regulation. Because the comments fall outside the first 15-day changes to the regulation, no further response is required.

D-56. Comment: What are the consequences for the auction administrator or financial services entity if they release confidential information? (PGE4)

> **Response:** The consequences will be specified in the contracts that we sign with the service providers. These have not yet been written, so we do not know what form they will take.

Miscellaneous

D-57. Comment: Section 95911(b)(4)(A) requires that unsold allowances be transferred into the Allowance Price Containment Reserve. WSPA believes that putting the unsold allowances into the reserve, as opposed as into the next auction, will artificially reduce the abundance of allowances and inflate a reserve that may not be needed and increase compliance costs. WSPA recommends that the unsold allowances should be put into next auction not to the reserve. (WSPA3)

> **Response:** We made the suggested change that unsold allowances be kept in the auction holding account for later auction. However, they will not be available at the next auction, as the commenter suggests. In order to deal with potential oversupply of allowances in the market, the allowances will not return to auction until two consecutive auctions have reached a settlement price above the auction reserve price.

D-58. Comment: CMTA reasserts comments made on December 9, 2010, for those elements of the cap-and-trade rule that have not been modified in the 15 day package, including our comments regarding the need for more information to set price collar levels for the allowance containment reserve account and that penalties for noncompliance should be less punitive and not take allowances out of the market. (CMTA3)

> **Response:** This comment was previously submitted during the 45-day comment period, and falls outside the scope of the first 15-day changes to the regulation. No further response is required.

D-59. Comment: Auctions are unknown and depend upon many variables. The unpredictability of auctions is not a positive point for conducting business in California. (NAIMA2)

> **Response:** This comment falls outside the scope of the first 15-day changes to the regulation. We did not change the inclusion of auctions in Subarticle 10 from the initially proposed regulatory language, and therefore it was not subject to comment under the first 15-day changes to the regulation. No further response is required.

D-60. Comment: The percentage limitation on purchase of GHG allowances at auction in sections 95911(c) and 95914(e) and the holding limit in section 95920(f) and (g) may prove to be too restrictive if and when CARB's ETS links to other GHG emission trading systems around the country. If we believe that such limits are necessary at this stage in the Cap and Trade program, PPG urges the Board to consider revising and expanding the purchase and holding limits in the future if and when the program is linked to other emission trading systems. (PPG1)

Response: We are currently in discussions with other members of the WCI on both the holding and purchase limits. We expect that some revisions may be necessary, in part to recognize different regulations and laws in the different jurisdictions, and in part to recognize the different market structure that we face after linking. Any changes to the limits would be part of a separate rulemaking that links the programs, not this regulation.

E. COMPLIANCE OBLIGATION

Municipal Solid Waste

E-1. (multiple comments)
Comment: The Commerce Refuse to Energy Facility located in the City of Commerce and the Southeast Resource Recovery Facility located in the City of Long Beach provide reliable and cost-effective solid waste disposal capacity to manage the needs of the residents and businesses of Los Angeles County. These facilities are equipped with the best available air emissions control technology and are currently reducing GHGE on a net basis. Additionally, the waste going to these two facilities has the potential to generate electricity for 55,000 homes in Los Angeles County. The previous draft of the regulations provided an exemption for existing waste to energy facilities due to the critical public service they provide. If these facilities have to bear the financial burden of compliance obligations, they may be forced to shut down, increasing the amount of waste sent to landfills for disposal in more remote locations. This would not only result in an increase in disposal costs for the County of Los Angeles residents but would also undoubtedly increase GHGE in the State, in contradiction to the goals of AB 32. Therefore, the County urges you to reinstate the exemption from compliance obligations for existing waste-to-energy facilities located in California. (CLADPW)

Comment: The Sanitation Districts are very concerned that CARB staff removed from the discussion draft of the 15-day amendments, language in section 95852.2 that excluded from compliance obligations, "Direct combustion of municipal solid waste with energy recovery in an existing permitted facility." We have not been provided with an adequate reason why this occurred. We therefore request that the language be re-inserted for the reasons described below. By way of review, the CARB Board passed a resolution at the 12/16/10 Board Meeting requiring "the Executive Officer to determine and report back to the Board a mechanism to satisfy all the risk of emissions leakage and compliance obligations of existing municipal waste-to-energy facilities in the proposed cap and trade program." Working to this end, the Sanitation Districts and Covanta Energy, have provided extensive analysis of the leakage to landfills that would occur if the three existing waste to-energy facilities in the State were placed in the Cap and Trade program. The analysis rested on a determination that if the post-recycled waste received by the facilities were instead landfilled, there would be a net increase in greenhouse gas (GHG) emissions. In this analysis, we remained conservative and used defaults that are consistent with the analysis CARB performed in estimating the AB 32, 1990 landfill GHG emissions inventory, and in the Early Action Landfill Methane Reduction Regulation. It is also consistent with defaults EPA has established for the NSPS for landfills and in many other documents, such as the Climate Action Registry Local Government Protocol and many of their offset protocols that rely on landfill methane avoidance. In addition to the basic analysis, many sensitivity analyses were performed (e.g., operating the landfill gas collection system operation past 70 years; a very conservative assumption), with all results pointing to the same conclusion; landfilling municipal solid waste that would otherwise be managed at a waste-to-energy facility, would result in a net increase in GHG emissions. Finally, as a further conservative measure, no credit was taking for additional GHG savings from post-combustion recycling and from avoided fossil emission from the utilities, which would normally be included in a true life-cycle analysis. In addition to the life-cycle analysis, we also addressed the question of why post-recycled waste would instead be landfilled if the existing waste-to-energy facilities were in the cap and trade program. Essentially, the three waste-to-energy facilities have no ability to control the incoming municipal solid waste, so there would be no opportunity to reduce fossil-fueled CO_2 emissions, leaving the purchasing of allowances as the only option for meeting compliance obligations. Furthermore, these facilities cannot spread the cost of allowances to a consumer base since their customers would instead choose the cheaper option of landfilling, leading to a net increase in GHG emissions (as outlined above). Clearly, requiring waste-to-energy facilities to be included in the Cap and Trade program will have the unintended consequence of incentivizing landfilling, and increasing GHG emissions. It would also have the unintended consequences of diverting funds local governments could use for municipal programs that support recycling or composting. Some environmental groups have opposed providing an exclusion from compliance obligations for these three facilities on the basis that beneficial recycling and composting will be reduced, and GHG emissions will be increased due to the burning of plastics, but if disposed of instead, plastics would not decompose. To the first point, waste-to-energy does not impact recycling or any other beneficial use of MSW, and in fact, these facilities complement these activities. The waste these facilities receive are post-recycled, or after any other beneficial use a region decides meets its diversion goals. If required diversion goals are increased, the waste-to-energy facilities would continue to receive waste that is post-recycled, but now meeting the higher diversion rates. To the second point, it is correct that burning plastics creates anthropogenic CO_2 and landfills sequester plastics. However, the lifecycle analysis provided to CARB assumes these facts, and yet the results consistently show that landfilling post-recycled waste instead of managing the same waste in a waste-to-energy facility results in a net increase in GHG. Also, bear in mind our analysis does not account for the fossil energy avoided due to managing the plastics, or any fossil-based MSW in a waste-to-energy facility, which would further increase the advantage waste-to-energy facilities have in reducing GHG emissions. (LASD3)

Comment: The 15-day modification discussion draft contained in section 95852.2, language that excluded from compliance obligations, "Direct combustion of municipal solid waste with energy recovery in an existing permitted facility." CCEEB appreciated the insertion of this language. However, when the draft 15-day modification language was released, this exclusion was removed. We request that the language contained in the discussion draft be re-inserted into section 95852.2. The owners/operators of these facilities have previously demonstrated to the satisfaction of CARB staff that the existing waste-to-energy facilities cannot spread the cost of allowances to a consumer base; haulers would simply take the post-recycled waste to the cheaper option, landfills, resulting in much higher levels of GHG. The facilities would have no choice but to absorb the cost of the allowances creating a huge financial burden for already financially strapped governments. Re-inserting the language is consistent with the Resolutions requirement to determine a “mechanism to satisfy all the risk of emissions leakage and compliance obligations of existing municipal waste-to energy facilities in the proposed Cap and Trade program." (CCEEB3)

Comment: Currently, in the proposed 15-Day Language, energy from waste is treated as a carbon source with its GHG impact determined solely by stack emissions, regardless of the benefit of reduced methane emissions realized by keeping waste out of landfills. Without a mechanism to recognize the benefits of energy from waste, there will be a leakage of GHG emissions to an uncapped sector. We request that ARB exclude the energy from waste facilities from the Cap and Trade program.

The California Cap and Trade program disregards the benefits of energy from waste as a tool to reduce GHG emissions in the waste sector and considers energy from waste a capped emission source. Conversely, landfills are an uncapped sector. Energy from waste facilities will be required to purchase compliance obligations, but landfills will not, despite landfills being a greater source of emissions per ton of post recycled waste managed. The current draft regulations do not provide a way to evaluate the avoided methane emissions from landfilling that these facilities prevent. We propose that the Cap and Trade program evaluate the GHG emissions between energy from waste and landfills.

Inclusion of energy from waste facilities in the Cap and Trade program ignores the scientifically recognized GHG benefits of this technology and will ultimately result in more GHG emissions generated in California. Covanta Energy and its community partners support a compliance obligation exemption for the three existing Energy-from-Waste facilities in California. An exemption is consistent with the major Cap and Trade systems currently in place: energy from waste facilities are is not included in either the European Union Emission Trading Scheme or the Regional Greenhouse Gas Initiative (RGGI). Inclusion of these facilities in the Cap and Trade program will introduce a significant economic burden on these facilities. This additional burden, and the fact that landfills face no compliance obligation under the program, raises a significant risk that waste will be diverted to landfills. Diversion of waste to landfills, as shown in the conservative analysis completed, will result in emissions leakage and higher GHG emissions from the state. Additionally, communities will lose revenues generated from the sale of electricity at these facilities. These are revenues that these communities use to fund their recycling programs. (COVANTA)

Comment: In California, there are three operating WTE facilities for MSW. These rule compliant facilities are conventional WTE facilities wherein the entire quantity of delivered MSW, except for white goods, is thermally treated. As a result, all of the non-biogenic materials are sources of CO_2 emissions. On the contrary, the City's Alternative Technology facility(ies) has a pre-processing system that will recover plastics and other non-biogenic materials from delivered MSW prior to it being processed for energy recovery. As a result, the remaining portion of the MSW for energy recovery is nearly 100 percent biogenic or mixed with a negligible portion of non-biogenic materials. The Bureau recommends that CARB amend section 95852.2(a)(7)(A) to not limit the exemption to only the biogenic fraction of the feedstock but include the entire MSW feedstock. (CLABS)

Comment: Section 95852.2(b)(5), Emissions without a Compliance Obligation, should not be limited to only the existing waste to energy facilities, but to also include new waste to energy facilities that can demonstrate that they can contribute toward achieving California's AB 32 goals set by the state legislature. (CLABS)

Comment: WM requests that a comprehensive GHG lifecycle assessment be used to determine relative GHG emissions of WTE facilities. A comprehensive life cycle assessment would find significantly fewer GHG emissions are released into the atmosphere when waste is generated into energy at a WTE facility, as compared to other energy generation and waste management methods. (WM3)

Comment: WTE technology has been proven in life-cycle assessments to lessen the amount of greenhouse gas emissions into the atmosphere as compared with alternative waste management and energy generation options. These life-cycle assessments have been conducted for individual WTE facilities as well as the WTE industry as a whole. WTE's direct and indirect greenhouse gas benefits are recognized by a large number organization and interests. The European Union Emission Trading Scheme, the European Environment Agency, and the Regional Greenhouse Gas Initiative all focus on lowering release of greenhouse gases into the atmosphere and, as part of their design, WTE is appropriately excluded from Cap and Trade requirements. California's Cap and Trade program should do the same. (WM3)

Comment: WM is concerned about CARB's recent reversal of its recognition of WTE's ability to lower greenhouse gases. The draft regulations initially proposed that the three existing WTE facilities would be excluded from a Cap and Trade compliance obligation, but the 15-day comment proposal eliminates this exclusion. This reversal threatens facilities' operations and could significantly increase municipal costs of waste management, environmental impacts from truck traffic and distance to disposal, and greenhouse gas emissions. If CARB imposes the Cap and Trade compliance obligation on existing WTE facilities, more waste will be disposed in landfills, more pollution will be emitted from increased transportation, more fuel will be consumed, fewer metals and recyclables will be recovered and more greenhouse gases will be emitted into the atmosphere. We strongly urge CARB to exclude WTE from any compliance obligation under the Cap and Trade Regulations. (WM3)

Comment: The Task Force supports providing a compliance obligation exemption for the three existing waste-to-energy facilities in California. These facilities were originally permitted under state legislation that mandated full support for these facilities. The three existing waste-to-energy facilities are equipped with the best available air emissions control technology and are currently reducing GHGE on a net basis due to avoided landfill methane. Los Angeles County residents depend on the two facilities located in Long Beach and Commerce for solid waste disposal services. Since neither facility can control their incoming, post-recycled waste stream to reduce GHGE, their only option is to purchase GHG allowances. Requiring these facilities to purchase allowances through the cap and trade program could result in severe unintended negative consequences. Therefore, we request that the full exemption provided to the existing waste to energy facilities be reinstated as provided in the previous draft of the regulation. (TASKFORCE)

Comment: Imposing a CO_2e allowance purchase requirement on WTE facilities would be the wrong choice on both policy and legal bases, and would result in more rather than less greenhouse gas (GHG) emissions in California. The Board recognized that fundamental reality in its July 8, 2011, Notice of Availability of Cap and Trade Discussion Draft and Workshop, explaining that such a requirement for WTE facilities would be counterproductive because including emissions from these facilities in Cap and Trade would cause statewide GHG emissions to increase as a result of diversion of waste to landfills. We commend the Board's straightforward recognition that an allowance purchase requirement for WTE facilities would be the wrong choice for California, and strongly encourage the Board to implement that position in the new regulations. (LGCRE2)

Comment: WTE facilities' life-cycle GHG emissions are lower than GHG emissions from landfills with energy recovery. WTE is a very clean and reliable energy source, reflecting State and federal requirements for the most advanced emissions control technology. In addition, WTE facilities are already highly efficient, and efforts to increase efficiency will continue entirely independent of the Cap and Trade program since efficiency improvements increase energy production and thereby reduce the net cost of recovering energy from waste. Although improved efficiency increases energy production, it does not reduce the amount of material that requires WTE processing or the CO_2e emissions that result. Unlike other stationary combustion sources, the purpose of a WTE facility is to make full use of a particular fuel, that is, to manage non-recyclable MSW through combustion with energy recovery, which is the best use for the portion of the waste stream that cannot be recycled. Unlike the combustion sources that are a primary focus of AB 32, WTE facilities' only means to reduce their GHG emissions would be to curtail service to their communities. That course of action would mean more waste disposal in landfills, however, and higher GHG emissions compared to processing the same waste at WTE facilities. Also, the concept of "cost-effective" allowance trading is not an option in the case of WTE facilities. Instead, WTE facilities will confront a continuing, long-term requirement to purchase CO_2e emission allowances at substantial additional cost, which is a requirement that will not apply to landfill CO_2e emissions. Consistent with these realities, none of the proposals considered by the 111th Congress for Cap and Trade regulation of GHGs would have applied to WTE facilities. Similarly, the Regional Greenhouse Gas Initiative also excludes WTE from Cap and Trade regulation. The only other alternative—purchasing CO_2e allowances—will mean a substantial permanent addition to the cost of WTE, which is already more costly than the less preferred alternative, landfilling. That sizeable new cost burden will jeopardize the ability of California's WTE facilities to continue to operate. Each of the scenarios just noted is clearly inconsistent with Cal. Code section 41516, which encourages WTE facilities as a means to "help alleviate the environmental and economic problems associated with municipal waste disposal, while at the same time producing additional supplies of energy and raw materials." For each of these reasons, the Board's proposed Cap and Trade Regulations and CO_2e allowance requirement should be modified to exclude WTE facilities. In the interest of achieving a significant future reduction in waste management sector GHG emissions in California, the same policy should also apply prospectively to new WTE capacity. (LGCRE2)

> **Response:** When the Board first considered the cap-and-trade regulation in December 2010, some stakeholders raised concerns about including waste-to-energy facilities in the cap-and-trade regulation. In response to this concern, the Board directed the staff to investigate whether including waste-to-energy facilities in the cap would result in "leakage" of greenhouse gas emissions. We do not expect that placing waste-to-energy facilities under the cap will increase greenhouse gas emissions. It is also not supported that including these facilities under the cap will lead to diversion of waste materials to other waste streams.
>
> There are important policy reasons to include waste-to-energy facilities in the cap. The cap-and-trade regulation is designed to both place an enforceable and declining cap on greenhouse gas emissions, and to send a price signal to encourage more efficient energy use. As part of this program, it is important to create a level playing field in order to send a consistent price signal. If we were to remove waste-to-energy facilities from the cap, it would inappropriately incentivize electricity generated by these facilities, since they would not be subject to the price signal. In addition, one of our partners in the Western Climate Initiative, British Columbia, is also planning to include waste-to-energy facilities as a covered sector in their cap-and-trade program.
>
> We recognize that the waste management system in California is complex and that it is important to consider the broader picture of waste management, which includes landfills, waste-to-energy facilities, recycling, and composting, as well as reduction in the use of resources at the front end. The Board has directed the Executive Officer to continue to work with Cal/Recycle and other stakeholders to evaluate opportunities for different options for handling of waste as directed in Board Resolution 11-32.

E-2. Comment: Section 95852.2 (a)(1) excludes from a compliance obligation such "[s]olid waste materials, including the biogenic content of solid waste materials that are not 100 percent biomass, as determined by methodology specified in ASTM D6866, based on exhaust sampling or fuel sampling (and fuel usage recordkeeping) at the specified frequency and tires which may use alternative tests." The sentence referencing tires may need to be edited and, at the least, requires a comma after "frequency" to differentiate tires from the methodology delineated for other solid waste. The sentence raises questions with regard to testing of other segregated industrial wastes listed as excluded from the Municipal Solid Waste definition if collected separately from MSW. Are tires the only segregated waste to be provided an alternative test, or may all industrial waste materials segregated from the municipal waste collection system use alternative tests appropriate for the material to determine the biogenic content and, thus, exclusion from compliance obligations? We support the use of consensus-based standards and tests best suited for the waste material for determining compliance obligations. (WM3)

> **Response:** The sentence in question was removed as part of the second 15-day changes to the regulation. No further response is required.

E-3. Comment: The BioEnergy Producers Association strongly supports the revision to Section 95852.2 (a)(7)(B) on page A-91 of the revised regulations ("Municipal Solid Waste"), which deletes the language following subsection (B), "Conversion to a clean burning fuel." Retention of the original language, which is derived verbatim from a scientifically inaccurate definition of "gasification" in PRC 40117, would have effectively eliminated "conversion to a clean burning fuel" from eligibility by requiring qualifying conversion processes to have zero emissions. (BPA)

> **Response:** No response is necessary.

Biomass/Biofuels

E-4. (multiple comments)
Comment: We support ARB's added language in section 95852.1.1(a)(2), which clarifies that an increase in fuel production includes "any amount over the average of the last three calendar years of production." We believe ARB should consider adding efficiency increases and the conversion of biogas to beneficial uses to the definition of increased capacity. If a methane capture facility installs a higher efficiency generator and thereby produces more carbon neutral electricity, overall emissions will be reduced. In addition, if a facility invests in converting a flare to a generator or undertakes other equipment modification, overall emissions similarly decline. Therefore, both these instances should meet the "increased capacity" standard and fall under the compliance exemption. Modify section 95852.1.1(a)(2) as follows:

> (2) The fuel being provided under a contract dated after January 1, 2012 must only be for an amount of fuel that is associated with an increase in the biomass-derived fuel producer's capacity, new production or recovery of the fuel that was previously destroyed without producing useful energy transfer. Increased capacity is considered any amount <u>(i)</u> over the average of the last three calendar years production <u>or (ii) associated with an increase in the efficiency of the facility, including an increase as a result of equipment upgrades, modification or refurbishment.</u> (EM)

Comment: ABC supports ARB's added language in section 95852.1.1(a)(2), which clarifies that an increase in fuel production includes "any amount over the average of the last three calendar years of production." ABC believes ARB should consider adding efficiency increases and the conversion of biogas to beneficial uses to the definition of increased capacity. If a methane capture facility installs a higher efficiency generator and thereby produces more carbon neutral electricity, overall emissions will be reduced. In addition, if a facility invests in converting a flare to a generator, overall emissions similarly decline. Therefore, both these instances should meet the "increased capacity" standard and fall under the compliance exemption. Modify section 95852.1.1(a)(2) as follows:

> (2) The fuel being provided under a contract dated after January 1, 2012 must only be for an amount of fuel that is associated with an increase in the biomass derived fuel producer's capacity, new production or recovery of the fuel that was previously destroyed without producing useful energy transfer. Increased capacity is considered any amount over the average of the last three calendar years production <u>or an increase in the efficiency of the facility</u>. (ABC2)

> **Response:** This section was split in the second 15-day changes to the regulation to make it easier to read the provision's requirements, as well as to specify that the recovery of the fuel be destroyed without producing useful energy transfer if a facility invests in converting a flare to a generator or undertakes other equipment modification. We could not add the suggested specific text regarding the increase in facility efficiency, as we do not have methods to track and verify those changes.

E-5. Comment: The Bureau recommends that special consideration should be given to the conversion technologies that are identical or similar to that of the City's Alternative Technologies project due to the fact that the proposed facilities have a pre-processing system to remove plastics and other non-biogenic materials prior to processing for biofuel/bioenergy production, and to extend the exemption to the entire MSW feedstock processed by these facilities and not limited to just the biogenic fraction. (CLABS)

> **Response:** We did not make a change in the current regulation, but will continue to evaluate how efficient and accurate such systems are in ensuring that only exempt biomass-derived fuels are ultimately combusted for energy production. We may consider changes to the regulation upon further data and evaluation as part of a separate rulemaking. We cannot exempt entire streams of MSW feedstock unless we are positive that the entire feedstock only contains biogenic materials.

E-6. (multiple comments)

Comment: WM is concerned that the proposed regulations would still place a compliance obligation on any portion of a conversion technology's emissions that are not biomass derived. WM recommends that CARB apply a life-cycle assessment approach to determine if a broader exemption from a compliance obligation is suitable for various types of conversion technologies. Many conversion technologies are relatively new and have yet to be fully demonstrated on a commercial scale. From a policy standpoint, subjecting these emerging conversion technologies to a compliance obligation for the non-biomass portion will place a significant burden on development. Innovative and diverse technologies for the beneficial use of waste are essential for sustainability. Yet, the Cap and Trade burden being placed on the very technologies that can deliver sustainable living can make them uneconomical, and stop investment, and therefore stop development before it begins. (WM3)

Comment: Conversion technologies' enhanced material and energy recovery may result in reducing GHG emissions, even if the non-biomass portion of the feedstock is included. At the least, these technologies should have the opportunity to demonstrate this possibility. Energy derived from waste conversion technology warrants comprehensive life-cycle assessment to evaluate the avoided emissions that would occur if the waste were managed by an alternative method. WM strongly requests that the proposed regulations be amended to allow assessment of the life cycle GHG benefits of energy recovery from waste, and thereafter base Cap and Trade compliance obligations for waste conversion technologies on this assessment. In the alternative, CARB can recognize now that policy reasons dictate conversion technologies should not be subjected to the cap if they are to develop as an alternative to disposal and more polluting forms of energy generation. (WM3)

> **Response:** The cap-and-trade regulation only looks at direct emissions at the covered entities. A lifecycle analysis is beyond the scope of this regulation and its intended purpose. We are committed to looking at this issue further and amending the rule, if necessary, to ensure that the compliance obligation is equitably placed to incent direct reductions of GHG emissions for all sectors involved in waste, waste-to-energy, and recycling. At this time, we believe that the regulation incents direct reductions at the waste-to-energy facilities without increasing emissions elsewhere. Board Resolution 11-32 directs the Executive Officer to work with Cal/Recycle and other stakeholders to evaluate opportunities for different options for handling of waste in a way that provides equitable treatment to all sectors involved in waste handling.

E-7. (multiple comments)
Comment: We strongly support the decision by ARB to remove the language in section 95852.2(a)(7)(B) that would have established criteria for the conversion processes that are producing a clean burning fuel from the biogenic fraction of the municipal solid waste stream. These criteria are applicable only to gasification in the Public Resources Code, and are used to determine if a gasification facility is defined as a solid waste disposal facility and if the energy produced qualifies as renewable under the Renewable Portfolio Standard. Applying these criteria to all technologies that produce a clean-burning fuel in determination of GHG reductions would be a misinterpretation of State Statue. We are pleased that the ARB is establishing clear policy based on sound science that all biogenic emissions are climate neutral. (BPA2)

Comment: WM supports exclusion from the compliance obligation under the Cap and Trade Regulations for conversion technologies that generate clean fuel from the biomass-derived portion of municipal solid waste (MSW), as is currently proposed in the 15-day comment version. Support for conversion technologies will lead to cleaner fuel and advanced technologies. The term "conversion" may apply to anaerobic digestion, gasification, acid-hydrolysis, and other technologies that beneficially use waste. Restrictions that appeared in the previously adopted regulations (see revised Section 95852.2(a)(7)(B)) were misplaced, and we support their deletion in the current proposal. (WM3)

Response: No response is necessary.

E-8. Comment: Our understanding of ARB's intent is that generation and sale of verified generating Climate Reserve Tons (CRT) under the Climate Action Reserve Landfill Project Protocol is intended to be allowable and not prevent biomethane from being exempt from a compliance obligation. However, the current draft language of section 95852.1.1(b) is not consistent with this position and needs clarification as to the intent. Please modify section 95852.1.1(b) as follows:

> (b*)* An entity may not sell, trade, give away, claim or otherwise dispose of any of the carbon credits, carbon benefits, carbon emissions reductions, carbon offsets or allowances, howsoever entitled, attributed to the fuel production that would otherwise result in holding a compliance obligation for combustion CO_2. Generation of Renewable Energy Credits is allowable and will not prevent a biomass-derived fuel that meets the requirements in this section from being exempt from a compliance obligation. <u>Generation and sale of verified Climate Reserve Tons (CRT's) under the Climate Action Reserve Landfill Project Protocol for voluntary capture of landfill gas and upgrading to Biomethane is allowable and will not prevent a biomass-derived fuel that meets the requirements in this section from being exempt from a compliance obligation</u>. (SES)

Response: We do not believe a change is necessary. The Regulation allows CO_2 emissions from biogas from a landfill participating in the voluntary offset program to be exempt from a compliance obligation if used at a covered entity in lieu of a fossil fuel.

E-9. Comment: The Task Force strongly supports the revisions to section 95852.2(a)(7)(B) that do not require compliance obligations for all conversion processes that are producing a clean-burning fuel from the biogenic fraction of the municipal solid waste stream. The initial draft criteria outlined unworkable requirements that are applicable only to gasification as described in the Public Resources Code. The purpose of this section is to determine if a gasification facility is defined as a solid waste disposal facility and whether the electricity produced is considered renewable under the Renewable Portfolio Standard. Applying the said requirements to all technologies that produce a clean-burning fuel through conversion in determination of GHGE reductions would be a misinterpretation of State statue. (TASKFORCE)

Response: No response is necessary.

E-10. Comment: We support the determination in the draft regulation that exempts biogenic emissions from a compliance obligation. The scientific consensus to date has reinforced the fact that biogenic emissions of CO_2, such as those produced from facilities that utilize biomass as a fuel source or feedstock, are climate neutral. (TASKFORCE)

Response: No response is necessary.

E-11. Comment: Section 95852.1.1(b), which restricts biogas projects from receiving carbon credits, offsets or allowances “attributed to the fuel production that would otherwise result in holding a compliance obligation for combustion CO_2,” seems overly broad and counter to what ARB had indicated in the past with respect to offsets from biogas projects. It is not clear whether biogas projects are prohibited from claiming ARB-issued offsets or offsets from other programs (such as CAR). If it is the former, then ARB has already determined which projects are eligible to earn offsets through its protocols, and any adjustments with respect to offset project boundaries and which credits can be claimed should be made in the protocols themselves. If it is the latter, it is not clear what authority ARB has to restrict offsets that are issued by non-ARB programs. In any case, the combustion of biogas releases biogenic emissions, which should be treated as carbon neutral. If an offset protocol awards credits for avoided methane emissions, that is a separate “reduction” from the value associated with combusting a biogenic fuel, and awarding this credit does not result in “double counting” downstream carbon benefits. If ARB seeks to restrict offsets from the combustion of the biogenic fuel (but not from avoided methane emissions), it would be much clearer if this adjustment were made in the Livestock Offset Protocol or other future methane destruction credit protocols developed by ARB. We urge ARB to clarify (as it has for RECs) that generation or use of generation or use of offset credits from methane destruction projects under the Livestock Offset Protocol and any future protocols that provide for credit methane destruction will not prevent biomass-derived fuels from being exempt from compliance obligations. Modify section 95852.1.1(b) as follows:

(b) ~~An entity may not sell, trade, give away, claim, or otherwise dispose of any of the carbon credits, carbon benefits, carbon emission reductions, carbon offsets or allowances, howsoever entitled, attributed to the fuel production that would otherwise result in holding a compliance obligation for combustion CO2.~~ Generation <u>or use</u> of Renewable Energy Credits <u>or of offset credits that are available for methane destruction</u> is allowable and will not prevent a biomass derived fuel that meets the requirements in this section from being exempt from a compliance obligation. (ABC2)

Response: We changed the regulation to ensure that biogas projects continue to receive offset credits for the destruction of methane. This revision was included to clarify that one is allowed to receive offset credits and no compliance obligation for combustion CO_2 emissions subject to the limits of the paragraph.

E-12. (multiple comments)
Comment: Emissions from bioenergy, whether from combustion to generate electricity or from liquid transportation fuels, should be under the cap and should not be exempted

from compliance obligations. The Cap and Trade rule should provide incentives for the lowest-carbon fuels, rather than a blanket exemption for all bioenergy. The biomass exemption provides a perverse incentive to cut down forests, with all of their sequestered carbon for energy purposes, which would actually make global warming worse. (SIERRACLUBCA5)

Comment: We strongly support ARB's decision not to exempt emissions from the incineration of municipal solid waste from compliance obligations. ARB's proposal in the proposed modifications to maintain exemptions from compliance obligations for other sources of biomass, however, remains fundamentally flawed for these same reasons. As we stated in our comments submitted in response to the proposed Cap and Trade Regulation: "These emissions affect California's ability to achieve AB 32's objectives just as much as emissions from other sources. Moreover, the climate impacts of any particular biomass facility will vary greatly, depending on fuel characteristics and sources, secondary emissions associated with harvesting and processing, land use impacts, and effects on future sequestration" (Center for Biological Diversity letter, December 15, 2010). We also described that "unchecked expansion of biomass energy—particularly the use of woody biomass to generate electricity—represents a double threat to the climate and to California's forests. Public incentives for biomass, embodied in renewable energy standards and other policies, a both threatening to exacerbate greenhouse pollution and putting increased pressure on the nation's forests by increasing the demand for woody fuel" (Center for Biological Diversity comment letter, December 15, 2010). The Center for Biological Diversity also submitted comments on this topic in conjunction with a coalition of environmental organizations, in which we described why greenhouse gas emissions from the combustion of woody biomass should be included under the cap and generate compliance obligations. "Entities combusting these fuels should be excused from compliance obligations only to the extent that they can demonstrate that the production and use of the biomass fuel resulted in reduced or avoided greenhouse gas emissions over a timeframe relevant to AB 32, that is, by 2020" (Group comment letter, December 14, 2010). That is, any exemption from compliance obligations must be based on an explicit and source-specific determination of the GHG emissions associated with the production and combustion of the feedstock. In the case of forest biomass, such a determination would need to take into account fuel characteristics and sources, secondary emissions associated with harvesting and processing, land use impacts, and effects on future sequestration. The blanket exemption proposed in both the original draft Regulation and the proposed modifications satisfies none of these criteria, and thus lacks any factual basis. The proposed modifications to the Mandatory Reporting Rule include new requirements for the reporting of basic information about the source and mass of forest biomass material. Monitoring and reporting requirements, however, do nothing to address the problems created within the Cap and Trade system by a blanket exemption from compliance obligations for biomass combustion. (CBD4)

Comment: The Pacific Forest Trust appreciates the additions to the Mandatory Reporting Rule to gather information regarding the source of forest biomass being combusted at large biomass facilities (section 95103(j)(2)). However, we reiterate our previous comments that not all biomass is created equally: biomass from different sources can have dramatically different carbon emissions. California's biomass policies will likely evolve in the coming years, and we urge ARB to retain a leadership role in that interagency discussion and to work toward an approach that more fully captures the accounting nuances of biomass combustion. (PFT3)

Comment: TWS requests the inclusion of bioenergy emissions under the cap. Section 95852.2 exempts a number of fuel source categories from compliance obligations. Biomass, used correctly, can be a part of the solution to the climate crisis, but the science does not support a blanket exemption for biomass. Biomass utilization can actually increase greenhouse gas emissions and undermine the goals of AB32. While some biomass use will result in de minimis carbon emissions or net negative carbon emissions, biomass cannot be assumed to be "carbon neutral." The net carbon impacts of biomass utilization vary depending on a number of factors including the source of biomass, emissions associated with its transportation, the method and efficiency of its conversion to useable energy, and the type of fuel source displaced by the biomass in question. Furthermore, net long term GHG benefits of wildfire fuel reduction treatments have significant regional variability and may change over time. A Cap and Trade system that does not account for important and significant potential variability of GHG emissions from biomass utilization compromises not only the integrity of the program cap, but may also have the unintended impact of incentivizing detrimental impacts on air, water, soil and wildlife habitat. (TWS)

> **Response:** We want to correctly identify and separately treat biomass-derived fuels from fossil fuels. Section 95103(j) of the MRR states that the operator or supplier must separately identify, calculate, and report all direct CO_2 emissions resulting from the combustion of biomass-derived fuels as specified in section 95115 for facilities, and sections 95121-95122 for suppliers. Biomass-derived fuel emissions must be identified by the source of fuel, as described in section 95852.2 of the cap-and-trade regulation. A biomass-derived fuel not listed in that section will be required to hold a compliance obligation under section 95852.1. For a fuel listed under section 95852.2, reporting entities must also meet the verification requirements in section 95131(i) of this article, or the fuel must be identified as an Other Biomass-Derived Fuel and be subject to a compliance obligation under section 95852.1. By not including biomass-derived fuels under the cap, we are recognizing that the use of a biomass-derived fuel is preferred over the use of fossil fuels at capped sources for the purposes of achieving the AB 32 emissions target.
>
> The scope of this regulation is to apply a compliance obligation on direct emissions from capped entities. Any lifecycle analysis of biomass-derived fuel and its potential emissions or impacts beyond the emissions at the capped entities is not within the scope of this regulation. The cap-and-trade program will include transportation fuels under the cap starting in 2015, therefore GHG emissions associated with the transport of biomass material will be covered under the cap. The Board approved an adaptive management plan to monitor

and adjust the program for unanticipated adverse forestry impacts as a result of offset projects. We do not believe that exempting emissions from combustion of woody biomass will result in the harmful removal of woody biomass from forests, as there are existing environmental protection laws that serve to protect against the denuding of the forests. The data collected under the MRR will help us monitor increases in biomass-derived fuels, types of specific fuels, and source location, to monitor for any changes to the use of biomass-derived fuels as a potential result of this program. The reporting requirements in the MRR have been subject to a public review and comment process as part of that rulemaking.

E-13. (multiple comments)
Comment: The transportation biofuels exemption would provide an implicit subsidy for surface transportation biofuels consumption regardless of their GHG profile, allow conventional ethanol to receive a competitive advantage over lower carbon alternatives, remove an incentive to move to lower carbon biofuels, and create a market for low-cost high-carbon biofuels that would not otherwise exist in California. We recommend that CARB remove the exemption for transportation biofuels, or retain an exemption as either a blanket exemption regardless of emissions, or with emissions thresholds such as 50 percent or 60 percent reduction from conventional fuels similar to federal benchmarks for advanced biofuels and cellulosic biofuel. (ICCT3)

Comment: We strongly recommend that CARB make a clear commitment to reevaluate the transportation biofuels exemption. This process should occur in time to make all necessary revisions prior to the implementation of Cap and Trade phase II, when surface transportation combustion emissions will be included. This exemption effectively assigns all transportation biofuels zero GHG emissions, creating an implicit subsidy, regardless of their actual GHG profile. This is also the case for other types of biofuels. The blanket exemption for biofuels would create leakage as transportation biofuels increase, and disadvantage advanced technologies such as hybrid, plug-in, and fuel cells. We recommend the following language be included in the final Statement of Reasons and is incorporated in the report to the Board:

- A blanket exemption would allow leakage from the cap due to increasing uncapped biofuels consumption from increased consumption of E10, potentially E15, and also E85;
- A blanket exemption would remove the conservation incentive created by cap and trade for a sub-set of fuels;
- A blanket exemption would treat all biofuels equally regardless of whether they are less carbon intensive than petroleum fuels and disadvantage advanced technologies such as hybrids, plug-in vehicles, and fuel cell vehicles.

Several options will be evaluated in 2012 for consideration prior to implementation of Cap and Trade phase II. First, ARB could remove the exemption. Fuel suppliers could either treat transportation biofuels the same as other surface transportation fuels, or use LCFS accounting methods to justify reduced allowance obligations. Second, ARB could retain an exemption as either a blanket exemption regardless of emissions, or with emissions thresholds such as 50 percent or 60 percent reduction from conventional fuels similar to federal benchmarks for advanced biofuels and cellulosic biofuel. The evaluation will consider a number of factors such as: the extent to which upstream transportation biofuels production emissions are captured under other cap and trade systems of similar stringency to California; the amount of leakage that would occur under a blanket exemption; and the availability of LCFS accounting tools; and effect on incentives for the lowest carbon advanced transportation technologies. (ICCT3, KUSTIN15)

Comment: We are completely opposed to the transportation biofuels exemption. (EDLA)

Comment: ARB's projected baseline emissions inventories do not appear to account for the expected shift from petroleum transportation fuels to biofuels in the future. While some of this increase may be accomplished with lower carbon biofuels, this shift would set back ARB's efforts to achieve 2020 GHG goals unless transportation biofuels are included in Cap and Trade or the overall level of the Cap and Trade is reduced to account for leakage due to expected increasing levels of transportation biofuels. Suppliers of biofuels should be able to apply for credits for certain fuels using an emission crediting system consistent with adopted emission factors, the best science, and verifiable methodologies. Treating all transportation biofuels as zero emissions is not supported by the best science and the ARB's own LCFS studies. It is critical to the integrity of the AB 32 program that ARB not create an emissions loophole for transportation biofuels. (KUSTIN15)

> **Response:** The cap-and-trade regulation will help transition California away from carbon-intensive fossil fuels to cleaner and more-efficient fuels. The fossil fuel portions of biofuels and bioenergy are under the cap. Transportation fuels and fuel suppliers will have a compliance obligation. However, biomass-derived fuels are exempt from a compliance obligation, since CO_2 emissions resulting from the combustion of biomass are considered biogenic. Emissions from biomass-derived fuels must be reported and verified pursuant to the MRR. Source categories that are not listed under section 95852.2 (Emissions without a Compliance Obligation) or that have not received a qualified positive or positive verification statement must be reported as "other biomass CO_2." Other biomass emissions that cannot be verified pursuant to the MRR are not considered biomass-derived, and will hold a compliance obligation.
>
> Furthermore, California's Low Carbon Fuel Standard (LCFS) addresses all lifecycle emissions (not just fossil fuel) in its regulation. The LCFS is designed to reduce the carbon intensity of transportation fuels 10 percent by 2020. Since GHG lifecycle emissions from transportation fuels are already regulated through the LCFS, lifecycle emissions do not need to be addressed in cap-and-trade. California's Low Carbon Fuel Standard comes from Executive Order S-01-07, which mandates that a statewide goal is established to reduce the carbon intensity of California's transportation fuels by at least 10 percent by 2020. This standard applies to all transportation fuels unless otherwise noted in the law. Specifically with regard to transportation fuels, ethanol from biomass (Agriculture,

Municipal, and Forestry) is covered under the LCFS, while biomass electricity is excluded from the regulation. As noted in the LCFS regulation, “The California Low Carbon Fuel Standard regulation, title 17, California Code of Regulations (CCR), sections 95480 through 95490 (collectively referred to as the “LCFS”) applies to any transportation fuel, as defined in section 95481, that is sold, supplied, or offered for sale in California, and to any person who, as a regulated party defined in section 95481 and specified in section 95484(a), is responsible for a transportation fuel in a calendar year.

E-14. Comment: ABC urges ARB to modify section 95852.1.1(a)(4). This section states that once a certification program is in place, a fuel which meets the requirements of sections 95852.1.1(a)(1) and 95852.1.1(a)(2) will always be considered to have met the requirements in section 95852.1. The phrase “once a certification program is in place” does not seem necessary, since ARB requires annual verification of the biomass derived fuels prior to the implementation of a certification program. Moreover, it is not clear when a certification program will be in place and this phrase could be read in such a way that a biomass derived fuel is not “always considered to have met the requirements in section 95852.1” until the certification program is in place. We believe ARB’s intent is for any biomass derived fuel which is adequately verified to continue to remain eligible for the compliance exemption, and since ARB has put rigorous verification requirements in place to do so, and will further be developing a certification program for biomass derived fuels, this phrase seems unnecessary. ABC urges ARB to delete this phrase. (ABC2)

Response: We removed this phrase in the Second 15-Day Change Notice.

E-15. Comment: We wish to compliment ARB on your treatment of biomass under section 95852 of the proposed Cap and Trade Regulation. Section 95852.2 provides a well-reasoned listing of biomass sources that have been shown to have lower emissions levels of greenhouse gases when used for energy production than when disposed of using conventional means, such as landfill disposal and open burning. Biomass power production in California provides approximately twice the greenhouse-gas benefit of other renewable resources by avoiding energy production using fossil fuels, and reducing the emissions of greenhouse gases associated with the recycling of the carbon in the biomass if it is disposed of by other, more conventional means rather than being converted to energy. (CBEA3)

Response: No response is necessary.

E-16. Comment: Section 95852.1.1(b) may go well beyond its intent. Because the section references “biomass-derived fuel,” it could be construed to include solid-fuel biomass. Moreover, it could be interpreted in such a way as to preclude the development of a protocol for the awarding of offsets for net reductions of greenhouse-gas emissions for the diversion of biomass from open burning, landfill burial, and other alternative fates to renewable energy production. We note that the definition of the REC that is used for RPS program compliance in California specifically excludes fuel-related attributes from the REC, a distinction that was enacted for the express purpose of allowing these attributes to be available to energy producers, if and when suitable protocols are developed. CBEA respectfully requests that the language be amended to clarify that this section does not refer to solid-fuel biomass. (CBEA3)

> **Response:** We modified this section to clarify that a certain number of offsets can be created and sold separately from the biofuel, in addition to RECs, and the biofuel will still avoid a compliance obligation under the cap-and-trade program. We made this modification to clarify eligibility of offsets from biomass and biogas projects. Any new offset protocols will be part of a separate rulemaking and, if warranted, we will change parts of the regulation to ensure that there are no inconsistencies.

E-17. Comment: Calpine supports the changes CARB made to the proposed regulation to clarify that emissions from geothermal generating units are exempt from the compliance obligation. However, because of an apparent error in the numbering of the relevant paragraphs, geothermal generating units, asphalt blowing at refineries, mobile equipment and well-site centrifugal and reciprocating compressors all appear to be classified as subcategories of combustion of biomass-derived portion of biomass-derived fuels (section 95852.2(a)(9)-(12)). Clearly none of these categories of emissions fit within the category of biomass combustion emissions. Calpine believes CARB's intent is clear in the 15-Day Modifications to exempt each of these categories, although the paragraphs were inadvertently numbered incorrectly. In the final rule, each of paragraphs (9) through (12) of section 95852.2(a) should be renumbered as their own independent subsection (b) through (e); what currently appears as subsection (b) should then be renumbered as subsection (f). (CALPINE3)

> **Response:** We made revisions to section 95852.2(b), which specifies that emissions without a compliance obligation include additional process, vented, and fugitive emissions from geothermal generating units; asphalt blowing at refineries; mobile equipment; and well-site centrifugal and reciprocating compressors.

E-18. Comment: CAPCOA supports reporting and verification procedures for biomass wastes that are workable within the existing practices of the biomass industry and does not support procedures that are a burden to, and discourage, the use of biomass wastes for renewable energy production. (CAPCOA2)

> **Response:** No response is necessary.

E-19. Comment: Clarify eligibility requirements for Biomass-Derived Fuels in section 95852.1.1(a). Although only certain types of biofuel contracts will meet the criteria in section 95852.1.1 for the combustion emissions to have no compliance obligation, this section should not prevent entities entering into contracts that do not meet the criteria. The change to the first line of section 95852.1.1(a) below is to clarify that, although there is no absolute requirement for biofuel contracts to meet the criteria, there is a benefit (in terms of a reduced compliance obligation) if the contract does meet the criteria. The heading of this section refers to the general term “biomass-derived fuels”, and so does section (a)(1). This term should be used throughout. There appears to be no reason to restrict this section to biogas and biomethane. This section refers to “contracts.” A “contract” should be defined to include transactions evidenced by recorded telephone calls, instant messaging, emails, and other types of electronic records that are commonly used for energy transactions. Section 95852.1.1(a) refers to assigned emissions. It is unclear how an assignment of emissions by the ARB relates to the reporting of emissions as biomass CO_2. Modify section 95852.1.1(a) as follows:

> (a) There is no compliance obligation for CO2 emissions from combustion of biomass-derived fuel procured under c~~C~~ontracts~~ for biogas and biomethane must~~ that meet one of the following criteria. Only the portion of the fuel that meets this criteria will be considered a biomass-derived fuel.~~ and is not subject to a compliance obligation if t~~ The emissions must be~~are~~ reported as biomass CO_2 in an emissions data report that has received a positive or qualified positive emissions data verification statement~~ or been assigned emissions~~: (SCPPA7)
>
> **Response:** We modified section 95852.1.1(a) to read as follows: "Biomass-derived fuel procured under contracts for biogas and biomethane must meet one of the following criteria. Only the portion of the fuel that meets one of these criteria will be considered biomass-derived fuel. Emissions from combustion of this fuel will not be subject to a compliance obligation when reported as Biomass CO_2 in an emissions data report that has received a positive or qualified positive emissions data verification statement and determined as exempt pursuant to section 95852.2 and 95103(g) of MRR."
>
> This modification clarifies that although there is no absolute requirement for biofuel contracts to meet the criteria, there is a benefit (in terms of a reduced compliance obligation) if the contract does meet the criteria. The heading of this section refers to the general term “biomass-derived fuels”, and so does section (a)(1); thus this section was modified to refer to biomass-derived fuels, not only biogas and biomethane.

E-20. (multiple comments)
Comment: “Certification” is referred to in section 95852.1.1(a)(4) but this term is not defined. Ideally, the term should be defined in both the MRR and the C&T Regulation. If fuel is from a certified facility, we understand that fuel will qualify as biomass-derived fuel. This should be clarified here. (SCPPA7)

Comment: The cross-references in section 95852.1.1(a)(4) do not appear to be correct. In relation to section 95852.1.1(a)(1) and (2), physical transfer of fuel under a contract could begin either before or after 90 days from contract execution, but not both. Section 95852.1 describes circumstances when biofuel does carry a compliance obligation, not requirements to be met in order for biofuel not to carry a compliance obligation. A better approach would be to clearly state the effect of receiving certification: If the biofuel production facility has been certified, biofuel from that facility will, as set out in paragraph (a), be biomass-derived fuel that is not subject to a compliance obligation. Modify section 95852.1.1(a)(4) as follows:

> (4) The fuel was produced at a fuel production facility that has been certified by an accredited certifier of biomass-derived fuels~~Once a certification program is in place, a fuel which meets the requirements of sections 95852.1.1(a)(1) and 95852.1.1(a)(2) will always be considered to have met the requirements in section 95852.1~~; or (SCPPA7)
>
> **Response:** Subsection 95852.1.1(a)(4) was removed. We require annual verification of the biomass-derived fuels prior to the implementation of a certification program. Our intent is for any adequately verified biomass-derived fuel to continue to remain eligible for the compliance exemption. Since we have rigorous verification requirements, and will further be developing a certification program for biomass-derived fuels, this provision is unnecessary.

E-21. Comment: An additional circumstance in which there may not be a contract for biofuel is where one entity owns both the fuel production facility and a separate generating facility at which the fuel is combusted. This situation applies to a SCPPA member, and should be included in section 95852.1.1. Modify section 95852.1.1(a)(5) as follows:

> (5) If the biogas or biomethane is used at the site of production~~,~~ and not transferred to another entity~~operator~~, or the fuel is used at another site owned or operated by the entity that produced the fuel, thus not requiring a contract, that~~e~~ entity ~~operator~~ must demonstrate one of the following:
>
> (A) The fuel has been combusted in California prior to January 1, 2013~~2~~; or
>
> (B) As of January 1, 2013, ~~T~~the fuel was not ~~previously~~ used to produce useful energy transfer. (SCPPA7)
>
> **Response:** We did not make the change at this time, but will further evaluate the implications for verifiability of this arrangement and consider adding it as part of a future rulemaking.

E-22. (multiple comments)
Comment: Section 95852.1.1(b) is very unclear. What types of credits would “otherwise result in holding a compliance obligation”? Is the intention of this section to allow offsets to be generated from avoided methane emissions at (e.g.) a landfill, as well as allowing the combustion of the biofuel to be zero-emissions, but only if the offsets are sold together with the biofuel? This accords with statements made by ARB staff in June 2011. If this is the ARB’s intention, SCPPA commends the recognition of the fact that the avoided methane emissions are separate from the emission reductions from using biogenic fuel in place of fossil fuel, and that no double counting arises. This recognition is in accordance with the science of emission reductions, with international

practice in offset markets and cap-and-trade programs, and with the ARB's own Compliance Offset Protocol for Livestock Projects. This protocol states on page 7 that it "does not account for carbon dioxide emission reductions associated with displacing grid-delivered electricity or fossil fuel use", meaning that offsets will not be issued for those emission reductions and that those emission reductions can therefore be recognized under the cap-and-trade program without creating double counting. However, as the offset-related and combustion-related types of emission reductions are separate from and additional to each other, there is no need to require the offsets to remain with the biofuel. Offsets for avoided methane emissions bear no relationship to the "compliance obligation for combustion CO_2." This situation is not equivalent to the relationship between renewable energy certificates (REC) and renewable energy, where either a REC or a megawatt hour of renewable energy can be counted as zero-emissions, but not both, as the REC is issued in respect of the zero-emission benefits of that megawatt hour of renewable energy. In the case of biofuel, emission reductions associated with displacing fossil fuel use are *additional to* the emission reductions associated with avoided methane emissions at (e.g.) the landfill. Separating the offsets from the biofuel does not strip the biofuel of its ability to reduce emissions by displacing fossil fuel. Once the step has been made to recognize that offsets can be generated for avoided methane as well as counting the biofuel combustion emissions as zero-carbon, there is no logical reason to require these two separate products to be sold together. Consider a biofuel purchaser that receives ARB offsets with its purchase of biofuel. Presumably that purchaser can use those offsets for compliance (subject to the quantitative limitation). Why should only the biofuel purchaser, and no other entity, be able to purchase those offsets and use them for compliance? Given the vagueness of the phrase "otherwise result in holding a compliance obligation for combustion CO_2," section 95852.1.1(b) as currently drafted could be interpreted in an even more limiting way, by prohibiting any sale of biofuel-related offsets (even to a biofuel purchaser). This interpretation should be clearly ruled out, as in this case the offsets would be rendered worthless (given that most biofuel producers do not have a compliance obligation of their own for which they could use the offsets they generate). Prohibiting biofuel offsets from being sold, or from being sold separately from the biofuel, would have negative consequences for both the offset market and the biofuel market. It would unnecessarily reduce the flexibility of biofuel producers to sell or otherwise transfer their products, it would reduce liquidity in the offset market, and it would be likely to increase the price of biofuel (as the price will need to incorporate the value of the offsets), without any additional environmental benefit. Section 95852.1.1(b) should be revised to allow offsets for avoided methane emissions, as well as RECs, to be generated in respect of biofuel and sold separately. Modify section 95852.1.1(b) as follows:

> (b) ~~An entity may not sell, trade, give away, claim or otherwise dispose of any of the carbon credits, carbon benefits, carbon emissions reductions, carbon offsets or allowances, howsoever entitled, attributed to the fuel production that would otherwise result in holding a compliance obligation for combustion CO2.~~ Generation ~~and sale~~ of Renewable Energy Credits <u>in respect of electricity from combustion of biomass-derived fuel, and offset credits in respect of avoided methane emissions at the site where biomass derived fuel is generated,</u> is

allowable and will not prevent <u>the CO2 emissions from combustion of</u> a biomass-derived fuel that meets the requirements in this section from being exempt from a compliance obligation. (SCPPA6)

Comment: Section 95852.1.1(b) is confusing, overbroad and unnecessary—and we urge ARB to delete it. The provision is overbroad in that it effects a sweeping restriction on offset credits and allowances. It is confusing in that it is unclear whether the restriction only applies to ARB issued credits and allowances, or also to credits and allowances from other programs—and, if it is the latter, it is unclear what authority ARB has to prohibit such uses. Additionally, the category of emissions and activities to which it applies is also vague and overbroad: "fuel production that would otherwise result in holding a compliance obligation for combustion CO_2." It is unclear to us what this means. In any event, this restriction is unnecessary to the extent that it applies to ARB offset credits because the regulations already clearly specify exclusive pathways for the creation of ARB offset credits: through the protocols. In particular, it is our understanding from discussions with ARB officials that the Livestock Protocol allows for offsets credits for avoided methane emissions, but not for emissions of biogenic CO_2 resulting from the use of biogas. Thus—if the intention of section 95852.1.1(b) is to prevent crediting for biogenic CO_2 emissions—it is not only overbroad and confusing, but also unnecessary. If ARB believes that it is not sufficiently clear in the Livestock Offset Protocol that credits are not available for biogenic CO_2 emissions, then it would be far better if ARB made the necessary modifications to the Protocol itself rather than utilize the overbroad and confusing language currently in section 95852.1.1. Moreover, it would be helpful for this provision to make clear (as it does for RECs) that generation or use of offset credits from methane destruction projects under the Livestock Offset Protocol—and any future protocols that provide credit for methane destruction—will not prevent biomass-derived fuels from being exempt from compliance obligations. Modify section 95852.1.1(b) as follows:

~~(b) An entity may not sell, trade, give away, claim or otherwise dispose of any of the carbon credits, carbon benefits, carbon emission reductions, carbon offsets or allowances, howsoever entitled, attributed to the fuel production that would otherwise result in holding a compliance obligation for combustion CO2~~. Generation <u>or use</u> of Renewable Energy Credits <u>or of offset credits that are available for methane destruction</u> ~~is~~ <u>are</u> allowable and will not prevent a biomass-derived fuel that meets the requirements in this section from being exempt from a compliance obligation. (CERP4)

Response: We modified section 95852.1.1(b) to clarify that a certain number of offsets can be created and sold separately from the biofuel, in addition to RECs, and that the biofuel will still avoid a compliance obligation under the cap-and-trade program. We received several comments stating that it was not clear whether biogas projects are prohibited from claiming ARB-issued offsets or offsets from other programs. Thus, we made this modification to clarify eligibility of offsets from biomass and biogas projects.

E-23. Comment: Plant material should be mentioned in section 95852.2(a)(8), as it is an important source of biogas and is identified in the definition of "biogas." (SCPPA6)

Response: We agree and made this change to section 95852.2(a)(8)(A).

E-24. Comment: Section 95852.2(a)(8)(B) refers to "waste." Arguments may arise as to whether a material constitutes "waste", particularly if the material is producing a useful product such as biogas. It would be clearer if the term "waste" were replaced with a more neutral term such as "material." Modify section 95852.2 as follows:

Emissions from the following source categories and from the combustion of the following fuel types count toward applicable reporting thresholds but do not count toward a covered entity's compliance obligation set forth in this article unless those emissions are reported as Other Biomass CO_2 under MRR. Emissions without a compliance obligation include:

(a) CO_2 ~~combustion~~ emissions from combustion of the following ~~biomass derived portion of~~ biomass-derived fuels:

(8) Biomethane and biogas from the following sources:

(A) All animal, plant and other organic material~~waste~~; or

(B) Landfills and wastewater treatment plants; (SCPPA7)

Response: We did not make this change. Not all organic material is eligible to be exempt from a compliance obligation. If it were, we would not need to list all of the particular types in this section. We believe "waste" is generally understood to mean material that is discarded because it has no use after a particular process has concluded.

E-25. Comment: When assessing which biofuels do not incur a compliance obligation, the regulation includes unnecessary specificity limiting the types of biofuel molecules considered. As currently written, these specifics will exclude many promising new technologies such as sugar-to-diesel, biobutanol and other "drop-in" fuels. The determination of what biofuels incur a compliance obligation should be based solely on the feedstock from which the fuel is manufactured. For example, if FAME biodiesel derived from vegetable oil is exempted, all biofuels made from vegetable oil should also be exempted. More inclusive language would avoid unintended barriers for new low-carbon biofuel molecules. Modify section 95852.2(a)(1), (2), and (3) as follows:

(1) Solid waste materials, including the biogenic content of solid waste materials that are not 100 percent biomass, as determined by methodology specified in ASTM D6866, based on exhaust sampling or fuel sampling (and fuel usage recordkeeping) at the specified frequency and tires which may use alternative tests, or any biofuel made from the biogenic content of these solid waste materials;

(2) Waste pallets, crates, dunnage, manufacturing and construction wood wastes, tree trimmings, mill residues, and range land maintenance residues; or any biofuel made from these specified types of wood materials or;

(3) All agricultural crops or waste; or any biofuel made from agricultural crops or waste or; (BP2)

Response: The Mandatory Reporting Regulation and the Reporting Tool will determine the fuels to be reported. Any biomass-derived fuels without a compliance obligation are listed in section 95852.2 of the cap-and-trade regulation. We will consider adding additional types of biomass-derived fuels as part of a future rulemaking. Our intent is not to discourage new biomass-derived fuels, but to make sure they are thoughtfully reviewed before exempting them from a compliance obligation.

E-26. (multiple comments)
Comment: We appreciate the revision to section 95852.1.1 to provide additional clarity. Unfortunately our conversations with other stakeholders over the past few weeks lead us to believe that the section is still subject to wide and contradictory interpretations. The following modification to the second sentence would clear up much of the confusion. Modify section 95852.1.1(b) as follows:

(b) An entity may not sell, trade, give away, claim or otherwise dispose of any of the carbon credits, carbon benefits, carbon emissions reductions, carbon offsets or allowances, howsoever entitled, attributed to the fuel production that would otherwise result in holding a compliance obligation for combustion CO_2. Generation of Renewable Energy Credits and generation of carbon offset credits from methane-related emission reduction activities, is allowable and will not prevent a biomass-derived fuel that meets the requirements in this section from being exempt from a compliance obligation. (TPI5)

Comment: PG&E's understanding of section 95852.1.1(b) is that an entity generating energy from biogas or biomass may sell carbon offsets as long as they retain sufficient "carbon credits, carbon benefits, carbon emissions reductions, carbon offsets or allowances" to make the CO_2 combustion emissions associated with the generation of energy zero net emitting. To improve clarity, PG&E recommends modifying the last sentence of the section. Modify section 95852.1.1(b) as follows:

(b) Generation of Renewable Energy Credits or offsets beyond those associated with the combustion of CO2 is allowable and will not prevent a biomass-derived fuel that meets the requirements in this section from being exempt from a compliance obligation. (PGE4)

Response: Section 95852.1.1(b) specifies that Generation of Renewable Energy Credits is allowable and will not prevent a biomass-derived fuel that meets this section's requirements from being exempt from a compliance obligation. However, to prevent double-counting of the environmental attributes of utilizing biomass-derived fuel, the section prevents another source from claiming the benefits realized or using the benefits to fulfill a compliance obligation, or for any other purposes. We modified this section to clarify that a certain number of offsets, in addition to RECs, can be created and sold separately from the biofuel, and that biofuel will still allow an entity to avoid a compliance obligation under the cap-and-trade program.

E-27. Comment: PG&E appreciates the clarifications that ARB made with respect to emissions without a compliance obligation. However, the tracking and enforcement of sources of wood and wood wastes is extremely difficult for energy generators and should be enforced by agencies with oversight of the harvesting of wood and wood wastes, not the ARB. An electricity generator burning wood waste meeting the California Energy Commission's (CEC) definition of biomass has no specific knowledge about the source of the wood being used in their operations. Accordingly, we recommend revisions to make it consistent with the CEC's definition of biomass. Modify section 95852(a)(4) as follows:

(4) Wood and wood wastes from timbering operations ~~identified to follow all of the following practices~~;

~~(A) Harvested pursuant to an approved timber management plan prepared in accordance with the Z'berg-Nejedly Forest Practice Act of 1973 or other locally or nationally approved plan;~~
~~(B) Harvested for the purpose of forest fire fuel reduction or forest stand improvement; and~~
~~(C) Do not transport or cause the transport of species known to harbor insect or disease nests outside zones of infestation or quarantine zones identified by the Department of Food and Agriculture and the Department of Forestry and Fire Protection, unless approved by these agencies.~~
(PGE4)

Response: We did not delegate our authority to oversee and enforce our regulations to another entity. The verification process is written to provide a consistent quality of rigor in review of all emissions with or without a compliance obligation under this program. Shifting part of that process to another entity or deferring to another process would affect the consistency and potentially the rigor of the program. The suggested deletions in the comment would make it impossible for us to verify that the biomass used was harvested in a sustainable manner under existing environmental regulations.

E-28. Comment: TNC urges ARB to continue to monitor the upstream carbon impacts related to the use of forest biomass for renewable energy. As stated in a previous letter submitted to ARB on April 8, 2011, while TNC acknowledges that there may be atmospheric and ecological benefits associated with the use of forest biomass for energy and fuels, such use may not be "carbon neutral" and may not always be ecologically beneficial. The current Cap and Trade Regulations effectively treat forest biomass (woody biomass) as carbon neutral by not requiring a compliance permit for this type of energy. We urge ARB to continue to monitor this issue closely as part of ongoing efforts to maintain the integrity of the cap and trade program and its impacts. In response to our comments and the comments of colleagues, ARB has made adjustments to the Mandatory Reporting Rule (MRR) to gather information that could help assess the carbon impact of forest biomass use for energy. We commend ARB for taking these actions, support those provisions, and will provide additional constructive comments on the MRR in a separate letter. As part of ARB's policy commitment to adaptive management, we urge ARB to adopt a process to periodically review the treatment of forest biomass for energy in the Cap and Trade program, including its GHG impacts and impacts to ecological sustainability. Furthermore, we request that ARB review the recommendations that will be developed for forest biomass through the Low Carbon Fuel Standard Sustainability Workgroup process and consider their application for forest biomass in the cap and trade program. (NC8)

> **Response:** Stakeholders have expressed their concerns over ARB excluding biomass from a compliance obligation by asserting that forest biomass would have an unfair economic advantage in comparison to energy sources with compliance obligations. The costs associated with collecting, processing, and transporting woody biomass waste in state is often greater than the value of the fuel that can be produced from these sources. Woody biomass is often considered an economically unviable energy source due to one (or many) of the following factors:
>
> - The source of woody biomass waste is often a great distance from the biomass power plant (or mill) facility;
> - Lack of infrastructure; and
> - Uncompetitive economics for biomass energy when compared with fossil fuel energy.
>
> Entities that use woody biomass for fuel will have to report certain types of data related to source and location to enable us to monitor this issue. ARB did not pursue an "adaptive management" approach to review the treatment of forest biomass in the cap-and-trade regulation.

E-29. Comment: Section 95852.1(b) of the regulation seems to be counterintuitive to the goals of AB 32. A facility producing biomass-derived fuels should not be required to abandon all carbon reduction credits and/or Renewable Energy Credits in order to ensure that the facility's emissions generated from the biogenic fraction of the feedstock does not count towards a compliance obligation. While we are in full support of establishing measures to prevent "double counting" of GHGE reductions, biogenic emissions are climate neutral and therefore should be exempt from compliance obligations without preconditions. Facilities utilizing the biogenic materials as a fuel source may have additional GHGE reduction benefits, and should be allowed to receive credit for those reductions so long as they are properly verified. Otherwise, there would be no incentive for developing new facilities utilizing biomass feedstock since such facilities would either be prohibited from realizing any carbon reduction benefits, or would be subject to potentially expensive compliance obligations. (CLADPW)

Response: We modified section 95852.1(b) to use the term "non-exempt biomass-derived CO_2," which is a CO_2 emission resulting from the combustion of fuel not listed under section 95852.2(a) or that is not verifiable under section 95131(i) of the MRR and is required to hold a compliance obligation. These fuel types may remain eligible to be exempt from a compliance obligation if they generate offsets for methane destruction as offset projects or if they also generate RECs.

E-30. Comment: CERP appreciates that ARB intends for a biomass derived fuel that is eligible for the compliance exemption under section 95852.1.1 to remain eligible for the compliance exemption in future years of the program. However, we urge ARB to clarify the language that attempts to codify this concept. Modify section 95852.1.1(a)(1) as follows:

(1) The contract for purchasing any biomass derived fuel must be in effect prior to January 1, 2012, and remain in effect or have been renegotiated with the same California operator within one year of contract expiration. (CERP4)

Response: We agree and made the change, except that the contract for purchasing any biomass-derived fuel must be executed prior to January 1, 2012, not necessarily be in effect by that date.

E-31. Comment: CERP respectfully requests that ARB add efficiency increases and the conversion of biogas to beneficial uses to the definition of increased capacity. If a methane capture facility installs a higher efficiency generator and thereby produces more carbon neutral electricity, overall emissions will be reduced. In addition, if a facility invests in converting a flare to a generator, overall emissions similarly decline. Therefore, both these instances should meet the "increased capacity" standard and fall under the compliance exemption. Modify section 95852.1.1(a)(2) as follows:

(2) The fuel being provided under a contract dated after January 1, 2012, must only be for an amount of fuel that is associated with an increase in the biomass-derived fuel producer's capacity, new production or recovery of the fuel that was previously destroyed without producing useful energy transfer. Increased capacity is considered any amount over the average of the last three calendar years production, an increase in the efficiency of the facility, or the conversion of a flare to a generator. (CERP4)

Response: We did not make this change because it is difficult to track and verify these types of changes. We will continue to evaluate this issue and consider rule modifications as part of a separate rulemaking.

Eligibility Requirements for Biomass-Derived Fuels, Section 95852.1.1

E-32. (multiple comments)
Comment: The phrase "once a certification program is in place" does not seem necessary, since ARB requires annual verification of the biomass derived fuels prior to the implementation of a certification program. Moreover, it is not clear when a

certification program will come into fruition, and this phrase could be read in such a way that a biomass-derived fuel is not "always considered to have met the requirements in section 95852.1" until the certification program is in place. We believe ARB's intent is for any biomass-derived fuel that is adequately verified to continue to remain eligible for the compliance exemption, and because ARB has put rigorous verification requirements in place to do so and will further be developing a certification program for biomass-derived fuels. This phrase is unnecessary and could lead to groundless ineligibility of fuels. CERP urges ARB to delete this phrase. (CERP4)

Comment: Removing the renegotiation requirement does not impinge on the environmental rigor that California is striving to achieve, since the subsequent language requires that physical fuel be transferred within 90 days and that the verifier be able to trace back to the previously eligible contract. At the same time, it ensures that fuel providers have the flexibility to renegotiate their contract without being subject to a one year time limit; such a limit could be unrealistic in many cases given the levels of regulatory approvals that must be obtained in California. Contract renegotiations and approvals can be lengthy processes in California, and could take longer than one year, especially if they are contingent on approvals by regulatory bodies such as the California Public Utilities Commission (CPUC). Given this reality, requiring the contract to be "renegotiated within one year of contract expiration" places a significant burden on the fuel provider when the timeline of events may be beyond its control. Therefore, CERP urges ARB to remove the phrase "and remain in effect or have been renegotiated with the same California operator within one year of contract expiration." In addition, CERP urges ARB to modify section 95852.1.1(a)(4)to further clarify the "once in, always in" concept. Modify section 95852.1.1(a)(4) as follows:

> (4) ~~Once a certification program is in place,~~ a fuel which meets the requirements of sections 95852.1.1(a)(1) and 95852.1.1(a)(2) will always be considered to have met the requirements in section 95852.1. (CERP4)

Comment: EM urges ARB to modify section 95852.1.1(a)(4) to further simplify the "once in, always in" concept. This section states that "Once a certification program is in place, a fuel which meets the requirements of sections 95852.1.1(a)(1) and 95852.1.1(a)(2) will always be considered to have met the requirements in section 95852.1." The phrase "once a certification program is in place" should be deleted, since ARB requires annual verification of the biomass derived fuels prior to the implementation of a certification program. Moreover, it is not clear when a certification program will be in place and this phrase could be read in such a way that a biomass derived fuel is not "always considered to have met the requirements in section 95852.1" until the certification program is in place. We believe ARB's intent is for any biomass derived fuel which is adequately verified to continue to remain eligible for the compliance exemption, and since ARB has put rigorous verification requirements in place to do so, and will further be developing a certification program for biomass derived fuels, this phrase seems unnecessary. (EM)

Response: We deleted all of the text that was previously in section 95852.1.1(a)(4). We received several comments urging us to simplify the "once in, always in" concept. We require annual verification of the biomass-derived fuels prior to the implementation of a certification program. Our intent is for any adequately verified biomass-derived fuel to continue to remain eligible for the compliance exemption. Since we have rigorous verification requirements, and will further be developing a certification program for biomass-derived fuels, this provision is unnecessary.

E-33. (multiple comments)
Comment: EM appreciates that ARB intends for a biomass derived fuel that is eligible for the compliance exemption under section 95852.1.1 to remain eligible for the compliance exemption in future years of the program. We appreciate that ARB has not restricted the compliance exemption to “long term” contracts and will allow any contract which meets the January 1, 2012, contract date (which we believe should be extended to January 1, 2013) to be eligible as a biomass derived fuel. We urge ARB, however, to clarify the language that attempts to codify this grandfathering provision. In section 95852.1.1 (a)(1), the phrase starting with “and remain in effect or have been renegotiated with the same California operator within one year of contract expiration” is not necessary for the codification of this concept, and in fact could create added uncertainty in the market. We propose the deletion of this phrase. This deletion is consistent with section 95852.1.1 (a)(3), which states that “The fuel being provided under a contract dated after January 1, 2012, is for a fuel that was previously eligible under sections 95852.1.1(a)(1) or (2), and the verifier is able to track the fuel to the previously eligible contract;”. If a contract expires, the language in section 95852.1.1(a)(3) already requires that the verifier be able to ensure the fuel’s eligibility under a contract that was in effect beforehand. In addition, further language in section 95852.1.1(a)(1)(A) requires that physical transfer of the fuel must begin within 90 days after a signed contract, or if physical transfer of the fuel begins after 90 days, then the first date of physical fuel transfer is considered the contract signing date. In other words, the language in the other conditions already conveys that if a contract is in effect by January 1, 2012, the biomass derived fuel will be considered eligible, and if the contract is renegotiated, the verifier must be able to trace the quantity of eligible biomass derived fuel to the original contract in order for the compliance exemption to be retained. (EM)

Comment: ABC appreciates that ARB intends for a biomass derived fuel that is eligible for the compliance exemption under section 95852.1.1 to remain eligible for the compliance exemption in future years of the program. We support ARB’s decision to not restrict the compliance exemption to “long term” contracts and to allow any contract which meets the January 1, 2012 contract date (which we believe should be extended to January 1, 2013) to be eligible as a biomass derived fuel. We urge ARB, however, to clarify the language that attempts to codify this grandfathering provision. In particular, section 95852.1.1(a)(1) states that the contract for purchasing any biomass derived fuel must be in effect prior to January 1, 2012 and remain in effect or have been renegotiated with the same California operator within one year of contract expiration. The phrase starting with “and remain in effect or have been renegotiated…” is not necessary for the codification of this concept. In particular, section 95852.1.1(a)(3) states the fuel being provided under a contract dated after January 1, 2012 is for a fuel that was previously eligible under sections 95852.1.1(a)(1) or (2), and the verifier is able to track the fuel to the previously eligible contract. If a contract expires, the language in section 95852.1.1(a)(3) already requires that the verifier be able to ensure the fuel's eligibility under a contract that was in effect beforehand. In addition, section 95852.1.1(a)(1)(A) requires that physical transfer of the fuel must begin within 90 days after a signed contract, or if physical transfer of the fuel begins after 90 days, then the first date of physical fuel transfer is considered the contract signing date. The language in the other conditions already convey that if a contract is in effect by January 1, 2012, the biomass derived fuel will be considered eligible, and if the contract is renegotiated, the verifier must be able to trace the quantity of eligible biomass derived fuel to the original contract in order for the compliance exemption to be retained. Requiring the contract to be "renegotiated within one year of contract expiration" places a significant burden on the fuel provider when the timeline of events may be beyond their control. Removing this language does not impinge on the environmental rigor that California is striving to achieve, since the subsequent language requires that physical fuel be transferred within 90 days and that the verifier be able to track the previously eligible contract. It ensures that fuel providers have the flexibility to renegotiate their contract without being subject to a one year time limit when this might be unrealistic given the levels of regulatory approvals that must be obtained in California. Therefore, ABC urges ARB to remove the phrase "and remain in effect or have been renegotiated with the same California operator within one year of contract expiration." (ABC2)

Comment: Section 95852.1.1(a)(1) refers to "the same California operator." The word "operator" is confusing in this context. For example, it could be read to refer to the operator of the biofuel facility (e.g. a landfill). "Purchaser" is clearer and more to the point. Section 95852.1.1(a)(1)(A) should be amended for clarity. Sections (A) and (B) are alternatives, not cumulative requirements. Modify section 95852.1.1(a)(1) as follows:

> (1) The contract for purchasing any biomass-derived fuel must be executed~~in effect~~ prior to January 1, 2013~~2~~ and remain in effect or have been renegotiated with the same California purchaser~~operator~~ within one year of contract expiration. The delivery of the fuel under the contract must meet the following requirements:~~;~~
>
> > (A) Physical transfer of the fuel must begin no later than 90 days after the execution date of the~~a signed~~ contract; or~~and~~
> >
> > (B) If physical transfer of the fuel begins more than 90 days after the contract is signed then for the purposes of this provision the first date of physical fuel transfer shall be considered the contract signing date; (SCPPA7)

Comment: The phrase starting with "and remain in effect or have been renegotiated" is not necessary for the codification of this concept because section 95852.1.1 already contains a requirement that the verifier be able to demonstrate that the fuel was eligible under a contract that was in effect prior to January 1, 2012. Modify section 95852.1.1, (a)(3) as follows:

(3) The fuel being provided under a contract dated after January 1, 2012, is for a fuel that was previously eligible under sections 95852.1.1(a)(1) or (2), and the verifier is able to track the fuel to the previously eligible contract; (CERP4)

Comment: If ARB determines that the phrase “and remain in effect or have been renegotiated with the same California operator within one year of contract expiration” must remain in section 95852.1.1, CERP urges ARB to remove the requirement for the contract to be in effect “with the same California operator.” This requirement is needlessly cumbersome. CERP sees no reason why contracting with a different California operator after the original contract expiration should bar entities from involvement with the program. Further, this requirement will allow operators with existing contracts to have unfair monopoly purchasing power within California with regard to specific producers. Accordingly, we recommend deleting “with the same California operator” and substituting “with a California operator.” (CERP4)

Comment: If ARB is concerned that requiring the renegotiated contract with the same operator will prevent placeholder contracts from being put into place and inhibit a subsequent informal market in trading “shell” contracts, ARB has already put mechanisms in place that would discourage such practices. First, physical transfer of the fuel must take place within 90 days of the contract being signed. Second, ARB under its mandatory reporting requirements already requires that they be informed of all upstream title holders of the fuel. In addition, most renewable contracts already go through an approval process with CPUC, and eligible renewable facilities must register with CEC (which requires that the fuel provider / marketer, the fuel production site and the downstream combusting entity be identified). These additional checks (in addition to ARB’s own reporting requirements) serve to discourage placeholder contracts and subsequent “shell” contract trading. Indeed, existing solar, wind, and other renewable projects are not restricted to renegotiating with the same counterparty in order to be considered a fuel eligible for the compliance exemption. Since ARB has recognized that biomass derived fuels which can be verified as such have biogenic emissions in nature, treatment of this resource should be at parity with other renewable resources. From the perspective of preventing leakage and upholding the integrity of the Cap and Trade program, it is immaterial whether the contract is being renegotiated with the same (original) counterparty or with another California entity. From a biomass derived fuel provider’s perspective, being tied to the same counterparty gives the buyer an unfair market advantage and limits the formation of a robust market for biomass derived fuels. Indeed, allowing market participants the flexibility to contract for fuel with various end users based on their unique requirements is crucial for the development of a biomass derived fuels, and ultimately to the benefit of compliance entities and California residents. Removing the restriction that the contract must be renegotiated with the same operator has no impact on the environmental integrity of the Cap and Trade program and at the same time supports a market for biomass derived fuels. We therefore recommend changing “with the same California operator” and to “with a California operator.” (EM)

Comment: Contract renegotiations and approvals can be lengthy processes in California, and could take longer than one year, especially if they are contingent on approvals by regulatory bodies such as CPUC. Given this reality, requiring the contract to be "renegotiated within one year of contract expiration" in section 95852.1.1(a)(1) places a significant burden on the fuel provider when the timeline of events may be beyond their control. Removing this language does not impinge on the environmental rigor that California is striving to achieve, since the subsequent language requires that physical fuel be transferred within 90 days and that the verifier be able to track the previously eligible contract. At the same time, it ensures that fuel providers have the flexibility to renegotiate their contract without being subject to a one year time limit when this might be unrealistic given the levels of regulatory approvals that must be obtained in California. Modify section 95852.1.1(a)(1) as follows:

> (1) The contract for purchasing any biomass-derived fuel must be in effect prior to January 1, 2012 ~~and remain in effect or have been renegotiated with the same California operator within one year of contract expiration~~. The delivery of the fuel under the contract must meet the following requirements: (EM)

Comment: Section 95852.1.1(a)(2) refers to "new" production or recovery of biofuel. "New" should be defined in this context. The cut-off date for biofuel contracts is the appropriate date for determining whether production or recovery is "new." It may also be helpful to define "useful energy transfer." Modify section 95852.1.1(a)(2) as follows:

> (2) The fuel being provided under a contract dated after January 1, 2013~~2~~ must only be for an amount of fuel that is associated with:
>
> > (A) an increase in the biomass-derived fuel producer's capacity, where an increase is considered any amount over the average of the last three calendar years' production;~~,~~
> >
> > (B) new production on or after January 1, 2013; or
> >
> > (C) recovery of the fuel that, as of January 1, 2013, was ~~previously~~ being destroyed without producing useful energy transfer~~. Increased capacity is considered any amount over the average of the last three calendar years production~~; (SCPPA7)

Comment: Section 95852.1.1(a)(1) requires that the contract for purchasing any biomass-derived fuel must "remain in effect or have been renegotiated with the same California operator within one year of contract expiration." ABC believes this requirement for the contract to be renegotiated with the same California operator to be unnecessarily cumbersome. If ARB is concerned that requiring the renegotiated contract with the same operator will prevent placeholder contracts from being put into place and inhibit a subsequent informal market in trading "shell" contracts, there are already mechanisms in place that would discourage such practices. First, physical transfer of the fuel must take place within 90 days of the contract being signed. Second, ARB under its mandatory reporting requirements, already requires that they be informed of all upstream title holders of the fuel. In addition, most renewable contracts already go through an approval process with CPUC, and eligible renewable facilities must register with CEC (which requires that the fuel provider / marketer, the fuel production site and the downstream combusting entity be identified). These additional checks (in addition to ARB's own reporting requirements) serve to discourage placeholder contracts and subsequent "shell" contract trading. Indeed, existing solar, wind, and other renewable projects are not restricted to renegotiating with the same counterparty in order to be considered a fuel eligible for the compliance exemption. Since ARB has recognized that biomass derived fuels which can be verified as such have biogenic emissions in nature, treatment of this resource should be at parity with other renewable resources. From the perspective of preventing leakage and upholding the integrity of the cap and trade program, it is immaterial whether the contract is being renegotiated with the same (original) counterparty or with another California entity. From a biomass derived fuel provider's perspective, being tied to the same counterparty gives the buyer an unfair market advantage and limits the formation of a robust market for biomass derived fuels. Allowing market participants the flexibility to contract for fuel with various end users based on their unique requirements is crucial for the development of a biomass derived fuels, and ultimately to the benefit of compliance entities and California residents. Removing the restriction that the contract must be renegotiated with the same operator has no impact on the environmental integrity of the cap and trade program and supports a market for biomass derived fuels. Modify section 95852.1.1(a)(1) as follows:

> The contract for purchasing any biomass-derived fuel must be in effect prior to January 1, 2012, and remain in effect or have been renegotiated with ~~the same~~ a California operator within one year of contract expiration. The delivery of the fuel under the contract must meet the following requirements; (ABC2)

> **Response:** New section 95852.1.1(a)(1) specifies that the contract shuffling date for purchasing any biomass-derived fuel must be in effect prior to January 1, 2012, and remain in effect or have been renegotiated with the same California operator within one year of contract expiration. This section is necessary to prevent contract shuffling wherein contracts are being diverted to California by entities seeking to avoid a compliance obligation for fossil fuels. Contract shuffling could allow fossil emissions to increase in states where the biofuel was previously combusted, which could result in no net change in emissions and emissions leakage. We changed the January 1, 2012, date from the original date in the MRR of January 1, 2010, in response to stakeholder comments that we needed to allow time for contracts to go through the California Energy Commission (CEC) process for RPS certification. We believe any further extension of the eligibility date will result in contract shuffling where covered entities will replace existing fossil fuel contracts with biomass-derived fuel contracts that will not result in an actual reduction of fossil fuel GHG emissions to the atmosphere. AB 32 requires that we prevent emissions leakage and contract shuffling is a type of emissions leakage.
>
> We clarified the text to allow for exempt biogas that is sold to a capped entity in California to change to another capped entity in the state and still be exempt from a compliance obligation.

E-34. Comment: A few modifications to the existing draft language would further support the creation of a robust market for pipeline biogas resources within the State and provide a key compliance option to California operators while ultimately serving to reduce costs for California businesses and residents. Therefore, we urge ARB to consider the following:

- Extend the Contracting Deadline for Purchase of Biomass-Derived Fuel to January 1, 2013, from January 1, 2012
- Simplify the grandfathering concept for biomass derived fuel that is purchased before the start of the program
- Ensure biogas projects continue to receive offset credits for the destruction of methane
- Remove the requirement that a contract must remain in effect with the same California operator
- Include efficiency increases in the definition for increased capacity. (EM)

Response: New section 95852.1.1(a)(1) specifies that the contract shuffling date for purchasing any biomass-derived fuel must be in effect prior to January 1, 2012, and remain in effect or have been renegotiated with the same California operator within one year of contract expiration. This section is necessary to prevent contract shuffling wherein contracts are being diverted to California by entities seeking to avoid a compliance obligation for fossil fuels. Contract shuffling could allow fossil emissions to increase in states where the biofuel was previously combusted, which could result in no net change in emissions and emissions leakage. The January 1, 2012, date was changed from the original date in the MRR of January 1, 2010, in response to stakeholder comments that staff needed to allow time for contracts to go through the California Energy Commission (CEC) process for RPS certification. We believe any further extension of the eligibility date will result in contract shuffling where covered entities will replace existing fossil fuel contracts with biomass-derived fuel contracts that will not result in an actual reduction of fossil fuel GHG emissions to the atmosphere. AB 32 requires that we prevent emissions leakage, and contract shuffling is a type of emissions leakage.

Further, we changed the regulation to ensure that biogas projects continue to receive offset credits for the destruction of methane. We included this revision to clarify that an entity is allowed to receive offset credits while not incurring a compliance obligation subject to the limits of the regulation.

We clarified the text to allow for exempt biogas that is sold to a capped entity in California to change to another capped entity in the state and still be exempt from a compliance obligation.

E-35. (multiple comments)

Comment: In section 95852.1.1(a)(1), the required contracting date for the purchase of biomass-derived fuel within California was extended to January 1, 2012. This change acknowledged that facilities which were undergoing contract negotiations and awaiting approval from California regulatory bodies such as CPUC would benefit from the additional time to complete these processes. Subsequent to this extension, a major legislative change has since taken place which has further lengthened the negotiation and approval processes for contracts which were expected to conclude earlier. In particular, the California legislature passed SBX1-2 in mid-2011, creating three tiers of California eligible renewable energy, and requiring new CPUC dockets and CEC guidance on the treatment of renewable energy (including biomethane). The end result is that contract negotiations which began in 2010 or even earlier have been stymied by the uncertainty associated with the passage of this bill. Thus, we propose the extension of the January 1, 2012, deadline to coincide with the start of the compliance portion of the cap and trade program, and to give entities the opportunity to complete the lengthy regulatory approval processes that contracts in California must go through. Extending the contracting deadline to January 1, 2013, allows the impacts of SBX1-2 to be incorporated into the contracting process by biomethane buyers and fuel providers. The extension also ensures that existing projects, which are already subsisting on thin profit margins, are not penalized for circumstances beyond their control. The extension further coincides with the start of the compliance portion of the cap and trade program (2013), which ARB itself proposed because a number of key issues associated with the construction of the Cap and Trade program, were pending. (EM)

Comment: In section 95852.1.1(a)(1), the required contracting date for the purchase of biomass-derived fuel within California was extended to January 1, 2012. We urge ARB to consider extending the deadline by an additional year to coincide with the start of the compliance portion of the Cap and Trade program, and to give entities the opportunity to complete the lengthy regulatory approval processes that contracts in California must go through. In particular, the California legislature passed SBX1-2 in mid-2011, creating three tiers of California eligible renewable energy, and requiring new CPUC dockets and CEC guidance on the treatment of renewable energy (including biomethane). The end result is that contract negotiations which began in 2010 or even earlier have been stymied by the uncertainty associated with the passage of this bill. While the original extension envisioned that existing contracts would be able to complete receiving the necessary approvals by January 1, 2012, the impacts of SBX1-2 were likely not taken into consideration for contracts in the middle of the negotiation and regulatory approval process. Extending the contracting deadline to January 1, 2013 allows the impacts of SBX1-2 to be incorporated into the contracting process by biomethane buyers and fuel providers. The extension also ensures that existing projects, which are already subsisting on thin profit margins, are not penalized for circumstances beyond their control. The extension further coincides with the start of the compliance portion of the cap and trade program (2013), which ARB itself proposed because a number of key issues associated with the construction of the cap and trade program, were pending. (ABC2)

Comment: SCPPA appreciates the change in the cut-off date for biofuel contracts from January 1, 2010, to the previous start date of the Cap and Trade program, January 1, 2012. However, the start date of the Cap and Trade compliance obligations has now been moved to January 1, 2013. Furthermore, the current cut-off date of January 1, 2012, is fast approaching but entities attempting to enter into contracts for biofuel still have little certainty as to the regulatory requirements affecting biofuel contracts. Some large biomethane transactions that are currently being negotiated may not be able to be finalized and approved by the end of 2011. For these reasons, SCPPA respectfully requests the cut-off date for biofuel contracts to be extended to January 1, 2013. References to 2012 should be changed to 2013 throughout section 95852.1.1. (SCPPA7)

> **Response:** The contract shuffling date for purchasing any biomass-derived fuel must be in effect prior to January 1, 2012, and remain in effect or have been renegotiated with the same California operator within one year of contract expiration. This section is necessary to prevent contract shuffling through which contracts are being diverted to California by entities seeking to avoid a compliance obligation for fossil fuels.
>
> Contract shuffling could allow fossil emissions to increase in states where the biofuel was previously combusted, resulting in a potential no net change in emissions and emissions leakage. The January 1, 2012, date was changed from the original date in the MRR of January 1, 2010, in response to stakeholder comments that we need to allow time for contracts to go through the California Energy Commission (CEC) process for RPS certification. We believe any further extension of the eligibility date will result in contract shuffling where covered entities will replace existing fossil fuel contracts with biomass-derived fuel contracts that will not result in an actual reduction of fossil fuel GHG emissions to the atmosphere. AB 32 requires that we prevent emissions leakage and contract shuffling is a type of emissions leakage.
>
> Contract shuffling is designed to prevent emissions leakage. If a California entity receives biomethane that was being combusted in another state, the facility in the other state would have to replace their biomethane with natural gas, and their fossil emissions would go up, resulting in emissions leakage and no true global reduction in CO_2 emissions. What we do not want to do is create a perverse incentive for all biofuels to be combusted in California because we have the largest incentive, while all other states would see increases in their fossil emissions. Our intent is not to disincentivize biomethane, but instead to incentivize new sources, rather than just swapping existing sources from one state to another.

E-36. Comment: LADWP recommends that the provision for eligibility for biogas contracts in section 95851.1.1(a)(2) be stricken from the draft regulation until further vetting on resource shuffling takes place. Eligibility requirements of biogas contracts should align with the 33 percent RPS. ARB proposes that no emissions compliance obligation would apply to biogas contracts in effect prior to January 1, 2012 that meet specific requirements for delivery and verification. Biogas contracts executed after January 1, 2012 would carry an emissions compliance obligation equivalent to unspecified natural gas (943 lbs/MWh), unless they were the result of a biofuel producers increased capacity, new production, recovery, or if the biogas could be tracked to a previously eligible contract. LADWP requests that ARB eliminate the January 1, 2012 deadline altogether, so that the California Cap and Trade program is more closely aligned with the 33 percent RPS. At minimum, the deadline should be shifted to January 1, 2013 to align with the start date of the compliance obligations under the Cap and Trade program. Increasing renewables from 20 percent to 33 percent represents a total of 11.4 MMT in emission reductions statewide after deducting emission reductions associated with tradable renewable certificates (REC). The RPS includes specific eligibility guidelines for the injection and delivery of biomethane into natural gas pipelines, but does not impose contract eligibility deadlines. To the extent that ARB does not recognize emission reductions associated with biogas contracts used for compliance with the 33 percent RPS, ARB will not fully achieve the projected emission reductions (11.4 MMT) associated with this measure, and additional demand will be placed on the supply of allowances, driving up the cost of allowances for all market participants. Modify section 95851.1.1 as follows:

> ~~(a) Contracts for biogas and biomethane must meet one of the following criteria. Only the portion of the fuel that meets these criteria will be considered a biomass derived fuel and is not subject to a compliance obligation if the emissions are reported as biomass CO2 in an emissions data report that has received a positive or qualified positive emissions data-verification statement:~~
>
> > ~~(1) The contract for purchasing any-biomass derived fuel must be in effect prior to January 1, 2012 and remain in effect or have been renegotiated with the same California operator within one year of contract expiration;~~
> >
> > > ~~(A) Physical transfer of the fuel must begin no later than 90 days after a signed contract; and~~
> > >
> > > ~~(B) If physical transfer of the fuel begins morethan-90 days after the contract is signed then for the purposes of this provision the first date of physical fuel transfer shall be considered the contract signing date;~~
> >
> > ~~(2) The fuel being provided under a contract dated after January 1, 2012 must only be for an amount of fuel that is associated with an increase in the biomass-derived fuel producer's capacity, new production or recovery of the fuel that was previously destroyed without producing useful energy transfer, increased capacity is considered any amount over the average of the last three calendar years-production;~~
> >
> > ~~(3) The fuel being provided under a contract dated after January 1, 2012 is for a fuel that was previously eligible under (1) or (2) above, and the verifier is able to track the fuel to the previously eligible contract;~~
> >
> > ~~(4) Once a certification program is in place, a fuel which meets the requirements of sections 95852.1.1(a)(1) and 95852.1.1(a)(2) will always be considered to have met the requirements in section 95852.1; or~~

~~(5) If the biogas or biomethane is used at the site of production, and not transferred to another operator thus not requiring a contract, the operator must demonstrate one of the following:~~

~~(A) The fuel has been combusted in California prior to January 1,~~ 2013 ~~2012; or~~

~~(B) The fuel was not previously used to produce useful energy transfer.~~

~~(b) As part of a biomass derived fuel's eligibility to avoid a compliance obligation no party may sell, trade, give away, claim or otherwise dispose of any of the carbon credits, carbon benefits, carbon emissions reductions, carbon offsets or allowances, howsoever entitled, attributed to the fuel production that would prevent the resulting combustion from not having a compliance obligation. Generation of Renewable Energy Credits is allowable and will not prevent a biomass derived fuel that meets the requirements in this section from being exempt from a compliance obligation.~~ (LADWP4)

Response: We disagree with this comment. We added a provision to Eligibility Requirements for Biomass-Derived Fuels section 95852.1.1, to accommodate the time required for the CEC to certify new RPS projects. We have heard from stakeholders who are concerned that many operators will not want to risk taking delivery of any substantial volumes of biofuel until CEC certification is received. Purchasers have an incentive to submit certification applications to the CEC promptly, because certification, if granted, is backdated to the date the certification application was submitted. These modifications should also better reflect the way in which the CEC certifies facilities as RPS-eligible with respect to particular fuels.

Fuels

E-37. Comment: The build-out of the hydrogen transportation infrastructure should not be burdened by an early penalty imposed on the hydrogen produced for use as a transportation fuel. Transportation fuels are not covered under the cap and trade program until the second compliance period. Since hydrogen is a low-carbon fuel, the carbon footprint of its production is equivalent to a conventional fossil fuel's carbon footprint during use. As such, hydrogen used as a transportation fuel during the first compliance period should be exempt from a compliance obligation, consistent with the absence of a compliance obligation imposed on fossil fuel based transportation fuels during the first compliance period. The hydrogen fuel exemption would also be consistent with the lack of a compliance obligation for natural gas used as a transportation fuel during the first compliance period. This temporary exemption can be realized by CARB allowing a reduction in a hydrogen producer's overall compliance obligation proportional to the fraction of total production which is sold as a transportation fuel. Alternatively, CARB could make an allowance allocation equal to the emissions associated with the amount of such hydrogen produced and sold as transportation fuel. (APC2)

Response: We recognize the potential of hydrogen as a clean transportation fuel. However, we do not agree that it is appropriate to exclude it from a compliance obligation or to provide an explicit incentive for its use through free allocation. The purpose of allowance allocation is not to "pick winners" among the many greenhouse gas-reducing technologies that may become more widely used in response to the carbon price signal created by the cap-and-trade program.

In addition, we modified the regulation to allow for a different allocation to liquefied hydrogen production facilities in the future, if necessary. If, in the future, any carbon costs from purchased electricity are included in consideration of the product benchmark values, the high level of indirect emissions from liquefaction of the hydrogen would likely lead to a different benchmark value for liquefied hydrogen. The current framework could also allow for a change in the leakage risk classification for liquid hydrogen based on any new information that may arise as we continue to analyze leakage risk per the direction in Board Resolution 10-42.

E-38. Comment: CARB must continue to develop the necessary regulatory infrastructure to include transportation fuels and natural gas in the second compliance period starting in 2015. (EDF4)

Response: This comment falls outside the scope of the first 15-day changes to the regulation. We will continue to work on various aspects of transportation fuel inclusion with stakeholders.

E-39. Comment: ICCT recommends allowing fuel providers the flexibility to choose between requiring allowances to cover the carbon content of the fuel, as required for other liquid transportation fuels; or allowing the use of LCFS accounting tools to determine the GHG burden of the fuel in order to adjust the compliance obligation. (ICCT3)

Response: This comment falls outside the scope of the first 15-day changes to the regulation. We will continue to work on various aspects of transportation fuel inclusion with stakeholders.

E-40. Comment: The Regulation contains very little detail as to how emissions from transportation fuels will be treated and included in the Cap and Trade program, including the expected contribution to the State's emission reductions goals. There is also the potential for significant market distortions in the different treatment of allowance allocation and use of allowance revenue amongst the various sectors. This treatment must be made consistent. Our concerns with respect to the treatment of transportation fuel emissions center around the ability to acquire sufficient allowances to cover fuel emissions and the ability to recover costs for these allowances with any degree of certainty. Given the size of the compliance obligation for fuel providers and the billions of dollars of allowances that will need to be purchased in order to allow these facilities to continue to operate, it is difficult to envision how the current system design will allow for cost pass through and recovery in a way that does not result in significant disruptions to the fuels market. As the rules around the treatment of transportation fuels in the Cap and Trade program are developed, BP strongly urges CARB staff to consider use of a fee on transportation fuels linked to the price of carbon in the Cap and Trade system. We believe the updated FED was very insightful in its inclusion of this concept in its evaluation of alternatives and believe the merits of this approach warrants serious consideration. This design for the inclusion of transportation fuels was contained in the federal Kerry-Graham-Lieberman draft bill from early 2010. This approach brings many benefits in its simplicity, carbon price transparency, economic efficiency, energy security and environmental certainty. A linked fee approach to transportation fuel emissions would: 1) maintain a market-based price signal to consumers, 2) improve the transparency of that price signal for consumers, 3) eliminate the need to compensate refiners for unrecovered costs associated with consumer emissions, and 4) provide a mechanism for transitional relief to fuel consumers and funding of transportation-related technology and infrastructure investment. (BP2)

> **Response:** This comment falls outside the scope of the first 15-day changes to the regulation. We will continue to work on various aspects of transportation fuel inclusion with stakeholders.

E-41. Comment: Incorporate provisions to review the energy, environment and economic implications of including transportation fuels under the cap; and review the Regulations to ensure level playing field for all transportation fuels. These reviews should be completed by January 2014. Shell believes that different regulatory approaches to CO_2 reduction are suited for different sectors. While we believe that market mechanisms such as Cap and Trade work most effectively for power and large industrial facilities, for road transportation, we believe different measures that independently target the fuel supplier, the vehicle manufacturer and the driver work best. There are already two programs in place that are intended to reduce GHG from fuels—the federal Renewable Fuel Standard and the California Low Carbon Fuel Standard. Including transportation fuel in the Cap and Trade program will add another layer of regulation. Additionally, including transportation fuels in the cap, will nearly double the emissions subject to this Regulation. Shell believes that before imposing an additional layer of regulation, ARB should further evaluate the impacts of including emissions from fuels in the Cap and Trade program in 2035 on energy availability, the environment and economics. In addition, further review is necessary to ensure a level playing field for all transportation fuel, including a level playing field for electricity used for transportation fuel and fossil fuel used for transportation fuel. The review should be completed and presented to the Board by July 2013 to allow sufficient time to modify the Regulation as necessary and provide entities' with sufficient planning time. (SHELLOIL)

> **Response:** This comment falls outside the scope of the first 15-day changes to the regulation. We will continue to work on various aspects of transportation fuel inclusion with stakeholders.

E-42. Comment: CalChamber remains concerned about the impact of including transportation fuels under the cap beginning in 2015 and thus requests that the inclusion of these fuels be revisited. With no Western Climate Initiative (WCI) trading partners ready to link, California will be alone in the Cap and Trade program. A California-only fuels under the program should be further evaluated with all economic impacts taken into consideration, including cost and consideration for the fact that California is already implementing the Low Carbon Fuel Standard (LCFS). Given the importance of transportation on California's economy, and the significance of energy costs to nearly every resident and business in the state, it is imperative that CARB do a thorough analysis of the economic impact of CARB's current proposal to include fuels in a unilateral Cap and Trade program; making sure that costs are minimal and total benefits to California are maximized. (CALCHAMBER3)

> **Response:** This comment falls outside the scope of the first 15-day changes to the regulation, which did not modify whether fuels were under the cap beginning in 2015. Thus, no further response is required. However, we will continue to work on various aspects of transportation fuel inclusion with stakeholders.

Applicability

E-43. Comment: CARB has endeavored to mimic the mandatory reporting applicability and calculation methodology of the U.S. EPA Mandatory Reporting Rule in many ways. However, in one aspect of the reporting rule relevant to our operations in the state there appears to be a critical difference. When operational control is shared between entities, CARB's assignment of reporting (and hence compliance allowance retirement) obligation shifts to the entity holding the permit to operate from the relevant air pollution control authority. The U.S. EPA MRR does not have such a provision, making the obligation to report rest solely on the owner/operator of a facility. With the modifications proposed to ARB's MRR, particularly under section 95114(a) which now is identical to the U.S. EPA MRR language (Subpart P of 40 CFR Part 98 section 98.160(c)), some uncertainty as to the States' intent has been created. We seek confirmation that, notwithstanding the different interpretation by U.S. EPA, the responsibility for developing, submitting and certifying the GHG emissions data report under Article 2, section 95104 and, subsequently, the obligation to satisfy an emission compliance obligation under Article 5, section 95811(a), rests with the entity holding the permit to operate under the conditions described within the specific definitions of "Operational Control" under section 95102 and "Operator" under section 95802; and the regulatory primacy stated under section 95000.5(d)(4). (APC2)

> **Response:** No change was made to the regulation based on the comments. The definition of "operator" is the same under the MRR as it is in the cap-and-trade regulation. Therefore, any requirements under the cap-and-trade regulation for operators apply to the same people that qualify as operators under the MRR.

Section 95852

E-44. Comment: Rio Bravo leases operation of the oil field to a third party operator, and it is this third-party operator that is listed on the oil and gas permits. To ensure that the entity that actually faces a GHG compliance obligation (Rio Bravo) receives industrial assistance for the oil produced, CARB should clarify section 95852(h) so that the Operator not only includes the entity that is listed on the oil and gas permit, but the entity that owns the oilfield. (ACERIO)

> **Response:** Industrial assistance is provided to industrial production activities such as oil and gas extraction. An oil-producing operator has to register with ARB and report the amount of production to receive free allowances.

E-45. Comment: Carbon dioxide suppliers are effectively included "under the cap." In section 95812, Inclusion Thresholds for Covered Entities, CO_2 captured from production processes or from a CO_2 stream to utilize for geologic sequestration is counted toward the applicability threshold of 25,000 metric tons per year. In section 95852, Emission Categories Used to Calculate Compliance Obligations, a CO_2 supplier's compliance obligation is calculated as "the sum of CO_2 supplied for use in California or exported for the purposes of geologic sequestration, minus CO_2 verified to be geologically sequestered through use of a Board-approved carbon capture and geologic sequestration quantification methodology that ensures that the emission reductions are real, permanent, quantifiable, verifiable, and enforceable." This deducts permanently geologically sequestered CO_2 from the compliance obligation; but placing these entities under the cap means no compliance offsets from CCS will be possible. However, incentivizing voluntary CCS offsets could be a way to create real, additional, permanent, verifiable, and enforceable GHG reductions. If necessary, ARB could restrict this opportunity to CCS projects located outside California. GHG reductions from carbon capture and permanent storage, quantified and verified using an ARB-approved Compliance Offset Protocol for this project type, could provide additional supply of high-quality offsets for compliance by covered entities. ACR recommends ARB consider removing CO_2 suppliers as a sector from having a compliance obligation and incentivizing CCS as offsets. Alternately, ARB could leave CO_2 suppliers under the cap in California, but allow CCS projects located outside California to generate offsets under a new Compliance Offset Protocol. (MARTINN3)

> **Response:** This comments falls outside the scope of the first 15-day changes to the regulation, which did not change how geologically sequestered CO_2 is treated in terms of a compliance obligation. We will continue to evaluate the potential use of CCS and an appropriate crediting mechanism.

E-46. Comment: SMUD points out that section 95852 incorrectly includes items (9) through (12) under subpart (a). These categories of emissions are not combustion emissions associated with biomass fuels, and these sections should be renumbered to be part of subpart (b), fugitive emissions without a compliance obligation. In addition, in subpart (b), there appear to remain some duplicative sections covering the same emissions twice. For example, section 95852(b)(2) exempts fugitive emissions from a variety of categories at refineries, but these emissions are also excluded in (b) (9) and (10). A general review and elimination of duplication of section 95852 is in order for clarity. (SMUD3)

> **Response:** This comment appears to refer to section 95852.2. We deleted items (9) through (12) in section 95852.2(a). We substantially rewrote section 95852.2(b) to clarify these sections.

E-47. Comment: Section 95852.2 details a list of fuel types that do not have a compliance obligation. WSPA believes that by using a specific list of fuels, ARB is limiting innovation for new fuels. WSPA recommends that ARB add provisions that allow fuel providers to identify other fuels that could qualify to not have a compliance obligation. (WSPA3)

> **Response:** We disagree. We will retain the authority to determine which fuels have a compliance obligation and add others or provide exemptions from a compliance obligation after review of each fuel type and a public rulemaking process.

E-48. Comment: Include a process to add to the list of fuels without a compliance obligation. Modify section 95852.2 as follows:

> Emissions from the following source categories and fuel types count toward applicable reporting thresholds but do not count toward a covered entity's compliance obligation set forth in this article unless those emissions are reported as Other Biomass CO_2 under MRR. <u>The Executive Officer may add additional source categories meeting similar criteria.</u> Emissions without a compliance obligation include: (CCEEB3)

> **Response:** No such criteria are provided in the regulation; therefore, we did not add this language. We will evaluate new fuels for exemptions as part of future rulemaking and through a public process.

E-49. Comment: The changes to section 95852.2 appear very significant and may amount to a large amount of potential emissions. In particular, exclusion of landfill methane emissions may result in large additional amounts of GHGs. The rule now appears to entirely exclude any SF_6 emissions, even though SF_6 is still listed as a regulated pollutant. (SCAQMD4)

> **Response:** Section 95852.2 lists fuels without a compliance obligation. Landfills are not required to report and are not included under the cap; therefore, it made no sense to list their emissions. There are currently no sources that are subject to reporting and holding a compliance obligation for SF_6. Therefore, it was removed as part of general clarifications in the text. We reserve the right to regulate and attach a compliance obligation to SF_6 in the future.

E-50. Comment: PG&E supports the formatting revisions that ARB made to section 95852.2 in the regulation, but there is still a lack of clarity in this section as to how vented and fugitive emissions from natural gas systems are treated. Vented and fugitive emissions from natural gas systems will be reported to ARB in an indirect manner under Natural Gas Supplier Reporting in section 95122 of the Mandatory Reporting Rule (MRR) and the Cap and Trade compliance obligation for these emissions is based on section 95122. There should be additional language in section 95852.2(b) that states clearly that the vented and fugitive emissions reported separately in section 95153 of the MRR do not have an additional cap-and-trade compliance obligation. Additionally, PG&E notes that section 95852.2(b)(15), labeled as "other venting and fugitive emissions not specified in the quantification methods," is vague. PG&E recommends that the type of emissions that would be included in this category should be more precisely defined, or it should reference an applicable section of the MRR so that there is no confusion. (PGE4)

> **Response:** We agree. Regarding the first suggestion in this comment, we added new text in section 95852.2(b)(4) specifically referencing section 95153 of MRR. Regarding the text in section 95852.2(b)(15) that may be too vague, we deleted that text. We added more precise definitions throughout section 95852.2(b).

E-51. Comment: Section 95852.1 now largely repeats requirements that are already set out in other sections. This section could be deleted without affecting the requirements that apply to biomass-derived fuels. If it is not deleted, some changes should be made to this section for clarity and to reduce redundant wording. The reference to "source categories" in section 95852.1(a) is not relevant here. As the first paragraph of section 95852.1 indicates, this section only addresses biomass-derived fuels. Modify section 95852.1 as follows:

> An entity that has emissions from <u>combustion of</u> biomass-derived fuels is required to report and verify its emissions pursuant to MRR and has a compliance obligation for every metric ton of CO_2e emissions ~~from biomass-derived fuels that would result from combustion or oxidation of all biomass-derived fuel from sources identified below~~:
>
> > (a) <u>from combustion of</u> ~~Source categories or~~ fuel types that are not listed under section 95852.2; or
> > (b) <u>from combustion of</u>~~Emissions from~~ fuels that do not meet the requirements of section 95852.1.1, or
> > <u>(c)</u> ~~those emissions~~ that are reported as Other Biomass CO_2 under MRR. (SCPPA7)
>
> **Response:** We agree and modified the regulation accordingly.

E-52. Comment: CERP generally appreciates the modifications and clarifications that ARB has made respecting emissions without a compliance obligation. However, we respectfully recommend that ARB modify the requirements that apply to wood and wastes so that they track those already established by the California Energy

Commission (CEC). Tracking of sources of wood and wood wastes is extremely difficult for covered entities and for agencies that do not have special expertise. For example, electricity generators burning wood waste meeting the CEC's definition of biomass are not expected to have specific knowledge about the source of the wood being used in their operations. For this reason, enforcement of such requirements should be done with other agencies that already have oversight responsibilities of the harvesting of wood and wood wastes. Modify section 95852.2(a)(4) as follows:

(4) Wood and wastes <u>from timbering operations</u> ~~identified to follow all of the following practices:~~

~~(A) Harvested pursuant to an approved timber management plan prepared in accordance with the Z'berg Nejedly Forest Practice Act of 1973 or other locally or nationally approved plan;~~

~~(B) Harvested for the purpose of forest fire fuel reduction or forest stand improvement; and~~

~~(C) Do not transport or cause the transport of species known to harbor insect or disease nests outside zones of infestation or quarantine zones identified by the Department of Food and Agriculture and the Department of Forestry and Fire Protection, unless approved by these agencies.~~ (CERP4)

Response: We partially agree with this comment and modified section 95852.2(a)(4) by removing paragraph (C). We did not adopt the commenter's other suggestions, primarily because paragraphs (A) and (B) are needed in order to report GHG emissions under the MRR section 95103(j).

E-53. Comment: We have concern that the structure of the Regulation provides no protection against suppliers of natural gas including a cost for allowances within the price they seek for natural gas even though covered entities will have to ensure they have allowances that cover emissions associated with their combustion of natural gas. Section 95852 provides that suppliers of RBOB, distillate fuel oils, natural gas liquids, and blended fuels are required to account for allowances for combustion of these fuels by their downstream users and there is not a concern regarding double-regulation since the downstream users are not required to account for such allowances. In contrast, while natural gas suppliers are required to hold allowances that represent the natural gas that is used by downstream users who do not fall under the scheme, they are not required to hold allowances for entities that fall under the scheme (covered entities) since those covered entities will be required to hold such allowances. Our concern is that there will be (at best) confusion over this issue and (at worst) manipulation of this issue such that downstream users of natural gas who are covered entities will face both prices of natural gas that includes the cost for allowances (even though the provider does not have to obtain such allowances) while the covered entity must still obtain the allowances itself. We note that ARB added language at section 95852(c)(3) such that ARB will provide to the natural gas suppliers a list of all their customers that are covered entities - including information on the aggregate natural gas volumes and emissions calculated from the supplier's natural delivered to the covered entity. This is a helpful addition in that it may help natural gas providers to understand which of their downstream users already have to pay for their allowances; however, it doesn't provide any mechanism for avoiding (or addressing) the situation in which the natural gas provider still embeds the cost of allowances into the sale price for the covered entity (resulting in double-payment). We are seeking that ARB consider incorporation of a mechanism to address this concern. This could include a requirement of transparency on the part of the natural gas provider along with a mechanism to discount the amount of allowances the downstream user is required to obtain in order to avoid a double payment. (UNITEDAIRLINES2)

> **Response:** We did not make a change at this time. Natural gas suppliers are not subject to a compliance obligation until the second compliance period. We will evaluate the issue and propose any needed changes as part of a future rulemaking. It will be up to the discretion of the natural gas supplier on how best to determine carbon cost pass-through. The facilities subject to a compliance obligation for natural gas can reduce their natural gas usage, thus lowering their direct compliance obligation and the amount they pay for natural gas.

Issuance of Compliance Instruments

E-54. Comment: The Regulation should add needed detail about the format and information contained in the serial numbers that will aid participants and the market as this program is implemented and as it evolves beyond California's borders. The serial number's format should identify Vintage Year, Compliance Instrument Type (Allowance or Offset Credit), Jurisdiction (California), and also identify project type for Offset Credits. Modify section 95820(a)(2) as follows:

> (2) The Executive Officer shall assign each California GHG allowance a unique serial number that indicates the annual allowance budget from which the allowance originates. <u>The serial number's format shall identify Vintage Year, Compliance Instrument Type (Allowance or Offset Credit), Jurisdiction (California), and also identify project type for Offset Credits.</u> (PGE4)

> **Response:** We did not change the regulation based on the comments. The requested requirement is part of program implementation and does not need to be specified in the regulation.

E-55. Comment: The language in section 95820(c) should allow the Board, as well as the Executive Officer, to terminate or limit the authorization to emit represented by a compliance instrument. (SCAQMD4)

> **Response:** We did not change the regulation based on the comments. ARB has sole authority to issue, regulate, or approve the allowances or offsets used in the cap-and-trade program.

Covered Entities

E-56. (multiple comments)
Comment: Considering the potential costs for the sector, the seasonality of the operations, the margins for the products, and the fact that ultimate costs will be absorbed by the farming community with no outlet to recover these costs, we ask that the food processing sector be excluded as a capped sector. The sector will continue to achieve cost-effective GHG reductions without the unnecessary costs of the program. (CCGG2)

Comment: Discussions with ARB staff are ongoing regarding first point of process being integral to the farm. As such, vegetable and fruit processing operations may be justified as being designated an uncapped sector in conjunction with the Agriculture Sector. (CALFP3)

> **Response:** We did not change the regulation based on the comments. Board Resolution 11-32 directs the Executive Officer to initiate a study to analyze the ability of the agricultural industry, including food processors, to pass on regulatory costs to consumers. The Executive Officer will identify and propose regulatory amendments, as appropriate.

E-57. Comment: For their CHP plants, several UC campuses would likely fall below CARB's Cap and Trade compliance threshold. This means that those campuses would not have to bear a carbon cost for natural gas usage until 2015. Thus, despite the fact that CHP plants meet campus electrical and thermal needs more efficiently than separate heat and power generation, and despite the fact that CARB identified increased deployment of CHP as an important mitigation measure in its AB 32 Scoping Plan, the proposed Cap and Trade program effectively penalizes the University for being an early adopter of CHP. (UC3)

> **Response:** No changes were made to the regulation based on the comments. Board Resolution 11-32 directs the Executive Officer to coordinate with State universities and stakeholders to evaluate options for compliance and propose regulatory amendments, as appropriate.

Threshold for Compliance Obligation

E-58. Comment: The potential impact on meeting the overall 2020 emission reduction goal for facilities initially in the program or opting-in that subsequently go below the threshold for inclusion and drop out of the program should be assessed. Combustion emissions will be controlled by having the upstream fuel under the cap after 2015, but other GHGs would not be. This could potentially compromise the ability to meet the 2020 reduction target. Also, we assume that facilities must reenter the program if their emission threshold subsequently increases. (SCAQMD4)

Response: We agree that there will be a need to assess the cap-and-trade program. We anticipate that its coverage is one aspect we will periodically assess.

E-59. Comment: Having facilities move in and out of the program as their emissions fluctuate will add an unnecessary administrative burden. We recommend that once a facility is in the Cap and Trade program they remain in, even when their emissions drop below 25,000 MT CO_2e per year. (SCAQMD4)

Response: We did not make a change to the regulation based on the comments. We have provisions that balance the need to accommodate fluctuations in applicability based on changes in emissions and program administration. These provisions are in both the MRR and the cap-and-trade regulation.

Opt-in Entities

E-60. Comment: Further clarifications are necessary to provide better guidance to entities that are considering opting in to the Cap and Trade Program under section 95813. Subsection (b) states that the Executive Officer shall evaluate opt-in applications and designate approved applicants as opt-in covered entities. This subsection should be clarified that the Executive Officer must approve as an opt-in covered entity any entity that meets the qualification requirements in subsection (a). Subsection (d) states that an opt-in covered entity may be eligible to receive freely allocated allowances subject to subarticles (8) and (9). This subsection should be changed to confirm that any approved opt-in entity shall be eligible to receive freely allocated allowances if the entity has submitted appropriate emissions and production data. Subsection (f) states that an opt-in covered entity that wishes to opt-out of the Cap and Trade program must apply to the Executive Officer. This subsection should be clarified to confirm that any opt-in entity's request to opt-out must be approved as long as the entity is in compliance with all applicable requirements, including reporting and allowance surrender. Section 95813 should be generally clarified to inform candidates on the timing of both opting in and opting out. We suggest that entities submit the opt-in request no later than March 31 of the present year in order to participate in the present year, assuming the Executive Director can expeditiously approve the opt-in request. Similarly, we suggest that entities submit an opt-out application by March 31 of the current year in order to be removed from the program for that year. (JM)

Response: No changes were made to the regulation based on the comments. It is clear in the regulation that opt-in entities are subject to all requirements of the program once they agree to participate in the program.

General Requirements

E-61. Comment: The Utilities request deleting the language in section 95850(b) that requires that the number of allowances required for submission is rounded to the nearest ton and suggest the additional compliance obligation above the whole number is carried forward into the next compliance obligation. This process is similar to that used by the Western Renewable Energy Generation Information System (WREGIS) to generate and track renewable energy credits (REC). For example, if a generator has 10.3 MWh of generation for the month of February, the generator is issued a WREGIS certificate for 10 MWh, and the 0.3 is rolled over to the next months' generation, or March. This same concept can be applied to the cap-and-trade program, whereby a covered entity's compliance obligation above the whole number can be carried forward to their future compliance obligation. The end result will account for all emissions without adding to an entity's compliance obligation for a specific period, which is essentially what rounding to the nearest ton does. Modify section 95850(b) as follows:

> (b) An entity's compliance obligation is based on the emissions number for every metric ton of CO2e for which a positive or qualified positive emissions data verification statement is issued, ~~rounded to the nearest whole ton~~, or for which there are assigned emissions pursuant to MRR. (MID3)

> **Response:** We disagree with this suggestion. While the provisions of the regulations and this commenter's suggestion likely make only a trivial difference over the entire market, the suggestion in this comment is somewhat akin to allowing borrowing—contrary to our policy position—except it goes beyond that. It not only allows an emission from the current compliance period to be met with a compliance instrument (or fraction thereof) from a future compliance period, but also does not require that compliance instrument to be surrendered until the end of the following compliance period.

E-62. Comment: The provisions of section 95850 set forth the general requirements for covered entities under the Program, and begins in subsection (a) with a statement that each covered entity is subject to the MRR. While this may be true, covered entities will have different compliance obligations under the MRR, and it is important that their respective compliance obligations not be generalized. Accordingly, NCPA recommends that all references to compliance with the MRR be drafted to provide "compliance with applicable MRR provisions." (NCPA3)

> **Response:** No changes were made to the regulation based on the comments. We believe that the regulation is clear that not all emissions reported under the MRR may be subject to a compliance obligation under the cap-and-trade program.

E-63. Comment: The verification statement includes emissions that do not carry a compliance obligation. Only the metric tons associated with the portion of the verification statement that carries a compliance obligation should be applicable in sections 95850(b) and 95852(a) pursuant to Subarticle 2 of MRR. Modify sections 95850(b) and 95852(a) as follows:

(b) A covered entity's compliance obligation is based on the emissions ~~number~~ for every metric ton of covered emissions (CO2e) as calculated in Subarticle 2 of MRR for which a positive or qualified positive emissions data verification statement is issued, rounded to the nearest whole ton, or for which there are assigned emissions pursuant to MRR. A covered entity's compliance obligation excludes emissions that are reported as part of a verification statement but are subtracted from the calculation of covered emissions.

(a) Operators of Facilities.

(1) An operator of a facility covered under sections 958111(a) and 95812(b)(1) has a compliance obligation for every metric ton of covered emissions (CO2e) as quantified under subarticle 2 of MRR for which a positive or qualified positive verification statement is issued per section 95131(c)(5) of MRR or for which there are assigned emissions, both for process emissions and stationary combustion emissions. If ARB has assigned emissions for the sources subject to a compliance obligation under sections 95852 and 95852.1, the facility will have a compliance obligation equal to the value of every metric ton of CO2e assigned emissions. The entity's compliance obligation will be assessed at the facility level unless otherwise noted under section 95812(c). (LADWP4)

Response: We modified section 95850(b) to clarify that an entity's compliance obligation is based on the verified emissions that are subject to a compliance obligation, not all verified emissions. We also modified section 95852(a)(1) with the reference to the MRR. We did not use this commenter's suggested text for either modification, but we believe our modifications achieve the commenter's intent.

E-64. Comment: For section 95850(c), we recommend that the most recent records be available on-site and be required to be produced to the Executive Officer "on request." If you allow 20 days for the production of any records, it allows the source plenty of time to forge nonexistent records. Making a "surprise" demand provides for better enforceability. (SCAQMD4)

Response: No changes were made to the regulation based on the comments. These provisions are standard practice for ARB's enforcement practices.

E-65. Comment: CLFP supports the CARB recommendation to reduce the record keeping requirement from ten to seven years. (CALFP3)

Response: Thank you for your support. However, with the Second 15-Day Change Notice, we modified the requirement back to 10 years. We initially reduced the requirement to seven years to be more consistent with WCI Partner recommendations. After further evaluation of our program, we concluded it was necessary to have the more stringent 10-year requirement.

E-66. Comment: Section 95123 of CARB's proposed rules requires "carbon dioxide suppliers" to comply with Subpart PP of 40 CFR Part 98 in reporting CO_2 emissions to ARB. The proposed definition of "carbon dioxide supplier" at section 95802(a)(45) omits the following list of activities that are excluded from EPA's carbon dioxide supplier GHG reporting regulation in Subpart PP, at 40 CFR 98.420(b): storage of CO_2 above ground or in geologic formations; use of CO_2 in enhanced oil and gas recovery; transportation or distribution of CO_2; purification, compression, or processing of CO2; and on-site use of CO_2 captured on site. The carbon dioxide supplier activities excluded by Subpart PP are not designed to emit CO_2 to the atmosphere. For California carbon dioxide suppliers, the failure to exclude these activities creates a surrender obligation under sections 95851(a) and 95852(g) for CO_2 that is not emitted to the atmosphere by the supplier. It also would unnecessarily increase the administrative burden on California suppliers by requiring them to track and report emissions using two separate protocols for the same activities. Since there are no provisions in Subpart PP for calculating the quantity of CO_2 associated with the excluded activities, it is impossible for a carbon dioxide supplier to comply with the requirement of proposed section 95123 that carbon dioxide suppliers comply with Subpart PP. Without CARB specific provisions for calculating the quantity of CO_2 "emissions" associated with the activities excluded from Subpart PP, a California "carbon dioxide suppler" conducting those activities cannot determine the required reporting method or the amount of its surrender obligation. Sections 95802(a)(45), 95851(a) and/or 95852(g) should be amended to exclude the following activities: storage of CO_2 above ground or in geologic formations; use of CO_2 in enhanced oil and gas recovery; transportation or distribution of CO_2; purification, compression, or processing of CO_2; and on-site use of CO_2 captured on site. (OPC2)

> **Response:** We agree and modified section 95802(a)(45), now section 95802(a)(47), accordingly. We also modified section 95852(g) to update it with the modifications in section 95802(a)(47).

E-67. Comment: The proposed regulation does not address all aspects of the Program that pertain to the treatment of natural gas suppliers, and this omission could be detrimental to some covered entities, resulting in a double obligation. In section 95811(c), suppliers of natural gas are included as covered entities, and elsewhere in the proposed regulation, the various obligations of these entities are discussed. Most notably, the modified text in section 95852 regarding Emission Categories Used to Calculate Compliance Obligations, adds provisions for calculating emissions that are not included in the compliance obligation. Beginning in 2015, the scope of the Cap and Trade Program will also include first deliverers of natural gas. Since the first compliance period focuses on the electric and industrial sectors, there is still some time to work through the details associated with the 2015 compliance obligation for natural gas suppliers. The modified text includes new provisions that clarify how the compliance obligation will be determined for suppliers of natural gas. Newly added sections 95852(c)(1) through (c)(4) provide that suppliers of natural gas will not have a compliance obligation for the delivery of natural gas to covered entities, "thus leaving the remaining balance of CO_2e emissions . . . as the compliance obligation for the supplier of natural gas." Section 95982(c)(2) provides that "ARB shall calculate the metric tons CO_2e of GHG emissions for natural gas delivered to covered entities."

NCPA recommends that the regulation also include an allocation of allowances to covered entities in an amount equal to the amount of CO_2e of GHG emissions for natural gas delivered to covered entities to offset the emissions associated with the compliance obligation that will be borne by the covered entities for the delivered natural gas. This adjustment does not create any additional allowances, as the compliance obligation associated with the supply of natural gas will have increased by an equal amount to the covered entity's free allocation; yet as more fully explained here, this adjustment would eliminate the potential for double charging the covered entity for the carbon cost. In order to avoid a potential windfall for natural gas suppliers and a double compliance obligation for entities such as electric generation facilities, NCPA recommends that the provisions of section 95852(c), regarding the calculation of the compliance obligations for natural gas suppliers, be modified to allow for the allocation of allowances to [electric sector] covered entities to address the fact that the current market structure does not enable natural gas suppliers to distinguish between sales to covered and non-covered entities for purposes of pricing their product in the market. In order to address the issues raised herein, NCPA recommends that the following revisions sections 95852(c) and 95852(c)(2):
(c) Suppliers of Natural Gas. A supplier of natural gas covered under sections 95811(c) and 95812(d) has a compliance obligation for every metric ton CO_2e of GHG emissions that would result from full combustion or oxidation of all fuel delivered to end users in California contained in an emissions data report that has received a positive or qualified positive emissions data verification statement or assigned emissions~~, less the fuel that is delivered to covered entities,~~ as follows:
(2) ARB shall calculate the metric tons CO_2e of GHG emissions for natural gas delivered to covered entities, and shall allocate to the covered entities an equivalent number of allowances to offset these emissions. The emissions with a compliance obligation will be the CO_2e emissions that received a positive or qualified positive emissions data verification statement or the assigned emissions from natural gas delivered to the covered entity by the supplier of natural gas. (NCPA3)

> **Response:** We did not take this approach, as we prefer to keep calculation of compliance obligation separate from the calculation of allowance allocation.

E-68. Comment: A company should be able to aggregate its compliance instruments among facilities, as opposed to meeting its compliance obligation on a facility by facility basis. (CALFP3)

> **Response:** The regulation specifies that it is entities, not facilities, that have compliance obligations.

Triennial Compliance Obligation

E-69. Comment: The 3-year compliance period in section 95856(b)(2) is intended to "smooth" out fluctuations in emissions from year-to-year. Allowances should be fungible for all years within a 3-year compliance period. LADWP recommends that subparagraph (3) be added to clarify that allowances issued during the compliance period may be used for emissions from that same period for the final triennial compliance surrender. Modify section 95856(b)(2) as follows:

> (2) To fulfill any annual compliance obligation, a compliance instrument must be issued from an allowance budget year within or before the year for which the compliance obligation is calculated, unless:
>
> > (A) The allowance was purchased from the Allowance Price Containment Reserve pursuant to section 95913; or
> >
> > (B) The allowance is used to satisfy an excess emissions obligation.
>
> (3) To fulfill a Triennial Obligation, compliance instruments from any compliance year within a compliance period may be transferred to a covered entity's compliance account. (LADWP4)
>
> **Response:** We agree with this comment and modified the regulation accordingly. Our modification differs from the text suggested by this commenter, but we believe that the modifications achieve the commenter's intent.

E-70. (multiple comments)
Comment: In section 95853(a), the modified text includes language that addresses the circumstances under which an entity would incur a compliance obligation, and references all emissions contained in a verified report. However, since not all emissions that are reported and verified are actually used for purposes of computing an entity's compliance obligation, NCPA recommends that this section be revised to reference only the applicable emissions calculation set forth in section 95852. Modify section 95853(a) as follows:

> (a) A covered entity that exceeds the threshold in section 95812 in any of the three data years preceding the start of a compliance period is a covered entity for the entire compliance period. The covered entity's triennial compliance obligation in this situation is calculated as the total of the ~~verified~~ emissions ~~that received a positive of qualified positive emissions data verification statement, or were assigned emissions pursuant to section 95131 of MRR~~ calculated in accordance with section 95852 for all data years of the compliance period. (NCPA3)

Comment: The wording in sections 95853 and 95855 on the calculation of a covered entity's triennial or annual compliance obligation does not accurately describe the covered emissions for electric sector entities. Not all of the emissions that an electric sector entity must report will form part of its compliance obligation. For example, biofuel emissions must be reported and verified but do not lead to a compliance obligation.

section 95852 sets out the details of the calculation of covered emissions for each covered sector. This section should be referred to whenever an entity's compliance obligation is being calculated. Modify section 95853(a) as follows:

> A covered entity that exceeds the threshold in section 95812 in any of the three data years preceding the start of a compliance period is a covered entity for the entire compliance period. The covered entity's triennial compliance obligation in this situation is calculated as the total of the emissions ~~that received a positive or qualified positive emissions data verification statement, or were assigned emissions pursuant to section 95131 of MRR~~ calculated in accordance with section 95852 from all data years of the compliance period. (SCPPA6)

Comment: Section 95853 should reference section 95852 since not all of the emissions reported may be subject to a compliance obligation. For example, biomass emissions must be reported and verified, but may not lead to a compliance obligation. Modify section 95853(a) as follows:

(a) A covered entity that exceeds the threshold in Section 95812 in any of the three data years preceding the start of a compliance period is a covered entity for the entire compliance period. The covered entity's triennial compliance obligation in this situation is calculated as the total of the emissions calculated in accordance with Section 95852 that received a positive or qualified positive emissions data verification statement, or were assigned emissions pursuant to section 95131 of MRR from all data years of the compliance period. (SEMPRA3)

> **Response:** We agree with this comment and modified this section accordingly. Our modification differs from that suggested by these commenters but achieves the same objective.

E-71. Comment: The calculation of the triennial and annual compliance obligations in sections 95853 and 95855 does not accurately reflect the manner in which the compliance obligations are calculated pursuant to section 95852. The Joint Utilities recommend that these sections be revised to reference section 95852 directly. Modify sections 95853(a) and 95855(a) and (b) as follows:

> (a) A covered entity that exceeds the threshold in section 95812 in any of the three data years preceding the start of a compliance period is a covered entity for the entire compliance period. The covered entity's triennial compliance obligation in this situation is calculated as the total of the emissions calculated in accordance with section 95852 ~~that received a positive or qualified positive emissions data verification statement, or were assigned emissions pursuant to section 95131 of MRR~~ from all data years of the compliance period.
> (a) An entity has an annual compliance obligation for any year when the entity is a covered entity except for the conditions specified in sections 95853(d) and 95856(d)(3); and
> (b) The annual compliance obligation for a covered entity equals 30 percent of emissions ~~reported~~ from the previous data year ~~that received a positive or~~

~~qualified positive emissions data verification statement, or were assigned emissions pursuant to section 95131 of MRR~~ calculated in accordance with section 95852. (JOINTUTILITIES)

Response: We disagree that there is a need for sections 95853(a) and 95855(b) to reference section 95852 directly, but we did modify sections 95853(a) and 95855(b) for greater clarity. We did not modify section 95855(a) based on the comments. It is important to qualify which emissions will be used, to calculate the compliance obligation as received from the MRR.

Quantitative Usage Limit

E-72. (multiple comments)
Comment: PG&E appreciates the modifications ARB made to the Quantitative Usage Limit that clarified that the usage limit is calculated based on a complying entity's compliance obligation for a compliance period rather than an entity's annual compliance obligation. However, because analysts forecast that there will be an insufficient supply of offsets at the outset of the program PG&E requests that the eight percent usage limit apply to a complying entity's total compliance obligation from January 1, 2013 through the current compliance year. This will allow time for the offset market to develop projects while maintaining the current cap on the use of offsets. Modify section 95854(b) as follows:

(b) The total number of compliance instruments identified in section 95854(a) that each covered entity may surrender to fulfill the entity's compliance obligation ~~for a compliance period~~ must conform to the following limit:

O_O/S must be less than or equal to L_O

In which:
O_O = Total number of compliance instruments identified in section 95854(a) submitted since January 1, 2013 to fulfill the entity's total compliance obligation ~~for the compliance period~~ through the current compliance year.
S = Covered entity's total compliance obligation beginning January 1, 2013 through the current compliance year.
L_O = Quantitative usage limit on compliance instruments identified in section 95854(a), set at 0.08. (PGE4)

Comment: SDG&E appreciates the change to the offset limit contained in the 15-day Modifications to the Cap-and-Trade Program that expanded the offset limit to compliance periods. However, there is no reason to limit the carryover to a compliance period. Allowing the limit to apply cumulatively would provide more flexibility without changing the intent of the regulation to limit the use of offsets to eight percent of the compliance obligation. Modify section 95854(b) as follows:

(b) The total number of compliance instruments identified in section 95854(a) that each covered entity may surrender to fulfill the entity's compliance obligation ~~for a compliance period~~ must conform to the following limit:

O_O/S must be less than or equal to L_O In which:
O_O = Total number of compliance instruments identified in section 95854(a) submitted since January 1, 2013 to fulfill the entity's total compliance obligation ~~for the compliance period~~ through the current compliance year.
S = Covered entity's total compliance obligation beginning January 1, 2013 through the current compliance year.
LO = Quantitative usage limit on compliance instruments identified in section 95854(a), set at 0.08. (SEMPRA3)

Comment: A company should be allowed to carry over excess or unused offset capacity into the next compliance period. (CALFP3)

Response: We disagree with these comments. Our policy decision is to limit the offset usage for each entity to eight percent of each compliance period, irrespective of whether an entity used its maximum number of allowable offset credits in a previous compliance period.

Annual Compliance Obligation, Section 95855

E-73. Comment: PG&E sees no reason why entities are not allowed to annually surrender up to 100 percent of their Compliance Obligation. While the Annual Compliance Obligation is set at exactly 30 percent of annual obligation, entities should be allowed to surrender and have retired up to 100 percent of their annual obligation, if they choose to do so. Modify section 95855(b) as follows:

(b) The annual Compliance Obligation for a Covered Entity equals thirty 30 percent of positive or qualified positive GHG emissions reported from the previous data year that received a positive or qualified positive emissions data verification statement, or were assigned emissions pursuant to section 95131 of MRR. Entities have the option to surrender and have retired up to 100% of positive or qualified positive emissions data verification statement, or were assigned emissions pursuant to section 95131 of MRR. (PGE4)

Response: No changes were made to the regulation based on the comments. The 30 percent is the minimum, and entities may opt to put more in their compliance accounts and request those be retired by the Executive Officer.

E-74. (multiple comments)
Comment: Section 95855, which deals with the calculation of the annual compliance obligation should be revised to include a reference to the provisions of section 95856(d)(3) that was added to clarify the fact that there is no annual obligation in the last year of any compliance period. This section should also be revised to include a

reference to the covered emissions calculation set forth in section 95852, for the same reasons set forth above. Modify section 95855 as follows:

> (a) An entity has an annual compliance obligation for any year when the entity is a covered entity except for the conditions specified in sections 95853(d) and 95856(d)(3); and
> (b) The annual compliance obligation for a covered entity equals 30 percent of emissions ~~reported from the previous data year that received a positive or qualified positive emissions data verification statement, or were assigned emissions pursuant to section 95131 of MRR~~ calculated in accordance with section 95852 (NCPA3)

Comment: Section 95855(a) should be revised to include reference to section 95856(d)(3). Section 95855(a) refers to years in which an entity does not have an annual compliance obligation, and section 95856(d)(3) states that there is no annual compliance obligation in 2015, 2018, and 2021 for the preceding years, only a triennial compliance obligation. Modify section 95855 as follows:

> (a) An entity has an annual compliance obligation for any year when the entity is a covered entity except for the conditions specified in sections 95853(d) and 95856(d)(3); and
> (b) The annual compliance obligation for a covered entity equals 30 percent of emissions ~~reported~~ from the previous data year ~~that received a positive or qualified positive emissions data verification statement, or were assigned emissions pursuant to section 95131 of MRR~~calculated in accordance with section 95852. (SCPPA6)

> **Response:** We disagree that these sections need to be revised. We believe the change suggested for section 95855(a) is unnecessary. We believe our modification to section 95855(b) has achieved the commenter's intent.

E-75. Comment: Clarify in section 95855(b) that not all reported emissions carry a compliance obligation, but only those that are identified in section 95852. Modify section 95852(b) as follows:

> (b) The annual compliance obligation for a covered entity equals 30 percent of emissions ~~reported~~ from the previous data year ~~that received a positive or qualified positive emissions data verification statement, or were assigned emissions pursuant to section 95131 of MRR~~ calculated in accordance with section 95852. (LADWP4)

> **Response:** We agree and added clarifying text that only emissions with a compliance obligation are considered in calculating the annual compliance obligation.

E-76. Comment: Annual surrender obligations also greatly reduce the flexibility of a three-year compliance period. CARB staff have asserted that this design element is necessary in the event that certain compliance entities declare bankruptcy during a compliance period. We have never seen a case made that demonstrates that this assertion by staff warrants such a drastic solution that is so potentially harmful to the operation of the market and to other compliance entities—or that other means, such as bonding or credit rating tests cannot be used to satisfy staff's concern. Mitigation of this risk, to the extent it exists, should be targeted at those who actually present a risk. The annual surrender obligation, for all but those with a demonstrated risk of insolvency, should be removed in order to allow the full flexibility provided by a multi-year compliance period. (BP2)

> **Response:** We do not agree that the annual surrender obligation negates the flexibility of the three-year compliance period. We do not expect any prudent covered entity to go more than 70 percent short in its obligations each year, so the provision should have little impact. Many covered entities have indicated that their intent is to match the timing of compliance instrument purchases to their emissions as closely as possible. Finally, we expect that the auction reserve price, which escalates over time, will help prevent market prices from collapsing due to short-run oversupply conditions. This removes a major incentive for covered entities to be short in covering their emissions during the compliance period.

Timely Surrender, Section 95856

E-77. Comment: To maximize the flexibility associated with the three-year compliance period, ARB should allow complying entities to surrender allowances from any year within that compliance period. PG&E believes that additional revisions to section 95856(b)(2), regarding compliance instruments valid for surrender, are required to ensure that the flexibility associated with the three-year compliance period is retained. As ARB has recognized, a three-year compliance period is particularly important to ensure that the Cap and Trade market continues to run smoothly during any condition that may affect the power markets (for example, periods of low California snowpack that result in low hydroelectric energy production). As currently written, section 95856(b)(2) appears to require that each ton of emissions be covered by an allowance from the same or a prior budget year, so that higher emissions during a dry 2013 could not be covered by 2014 vintage allowances even though the surrender demonstration for the remaining 70 percent obligation that was accrued in 2013 is not until 2015. Modify section 95856(b)(2) as follows:

> (2) To fulfill any Compliance Obligation, a Compliance Instrument must be issued from an allowance budget year within or before the ~~year~~ <u>Compliance Period</u> for which the Compliance Obligation is calculated. (PGE4)
>
> **Response:** We modified section 95856(b)(2) to clarify that for an annual compliance obligation, an allowance from that vintage or earlier must be used. We also added clarifying language that for a triennial compliance obligation,

allowances with a vintage for the end of the compliance period or earlier may be used. We do not want to make any modifications that would result in borrowing vintages of allowances for compliance from the next vintage year.

E-78. Comment: PG&E supports the change from dual annual compliance deadlines to a single deadline of November 1st. PG&E supports the revised deadline to allow more time for covered entities to obtain compliance instruments and limit supply shocks to the market. (PGE4)

Response: Thank you for supporting this revision.

E-79. Comment: There is no reference to a specific subarticle in section 95856(b)(1). This is important to know as this section is referenced in the holding limit provisions in section 95920(c)(2). Modify section 95856(b)(1) as follows:

(b) Compliance Instruments Valid for Surrender.

(1) A compliance instrument listed in Subarticle <u>4 section 95820 and section 95821</u> may be used to satisfy a compliance obligation. (LADWP4)

Response: The commenter is incorrect. That section does reference Subarticle 4.

E-80. Comment: The Utilities urge CARB to clarify the treatment of excess compliance instruments in a compliance account that exceed the entity's compliance obligation in section 95856. The Utilities are unclear as to the process where, accidentally or due to circumstances varying from forecasts, a compliance entity transfers more compliance instruments into its Compliance Account than are required to meet a compliance obligation. Section 95831(a)(4)(B) states that once a compliance instrument is transferred into the Compliance Account it may not be removed by the entity, and section 95856(g)(1) states that the Executive Officer shall retire the compliance instruments surrendered once it has determined that the covered entity has met its compliance obligation. The Utilities request the language above to be included in section 95856(g)(1) clarifying that CARB would not retire any compliance instruments in excess of the compliance obligation unless specifically requested by the covered entity. In addition, the Utilities request that either the term "surrender" be defined within the regulation in a manner that is consistent with section 95856(c). Alternatively the term "transfer" could be used in place of "surrender" since the two terms appear to be used interchangeably and "transfer" is a defined term under section 95802(a)(268). Modify section 95856(g)(1) as follows:

(1) Retire the compliance instruments surrendered <u>provided, however, in the event the number of compliance instruments contained in a compliance account at the time of retirement exceeds the compliance obligation, the Executive Officer shall retain the excess instruments in the compliance account unless the entity requests the excess instruments be retired or returned to the entity's holding account</u>; and (MID3)

Response: No changes were made to the regulation based on the comments. The compliance account does not serve as a "savings" account. The proposed changes to could be used to circumvent the holding limit, which is essential for market integrity.

E-81. Comment: We strongly urge ARB to retain the prohibition on borrowing contained in section 95856. Allowing entities to submit future vintage year allowances for compliance at an earlier date encourages entities to delay undertaking the necessary planning and investment decisions to be compliant over the course of the program. Retaining a firm prohibition on borrowing is all the more essential given ARB's proposal to increase the advance auction from two to ten percent. Advance auctioning ten percent of future vintage year allowances will inject liquidity in the market early on at the expense of later budget years, when the cap is much larger. While we see merit in this approach, advance auctioning that amount of future vintage year allowances will become extremely problematic should the firm prohibition on borrowing be relaxed. (KUSTIN16)

Response: Thank you for the support.

E-82. (multiple comments)
Comment: Business fluctuations at the end of a compliance period are anticipated. These fluctuations could adversely impact the smooth operation of the market. CCEEB recommends that vintage allowances (i.e. borrowing from current year) be allowed to be used during the true-up period. This will provide a mechanism for the end of compliance truing-up that will increase market confidence. (CCEEB3)

Comment: The current Regulation only allows emissions banking in the Cap and Trade. CARB should allow borrowing allowances with some limits and standards. The ability to borrow will aid in reducing costs and allow companies to meet obligations without penalty for short periods of time. (CALFP3)

Response: We disagree. Our policy decision is not to allow borrowing during the true-up period.

E-83. (multiple comments)
Comment: Regarding section 95856(d)(1) and (2), the previous rule version had six weeks after the end of each year or compliance period to surrender compliance instruments. The proposed changes now give five or seven months, depending on when the facility submits its greenhouse emission reports. We have previously commented that a three-year compliance period makes it more difficult to find and enforce against situations where not enough emissions were reported and/or not enough compliance instruments were surrendered. Extending the deadline for surrendering compliance instruments for this long is not necessary. RECLAIM has a 60 day year-end compliance reconciliation period which works well. There will not be adequate incentive for a facility to retire compliance instruments in a timely fashion if

five or seven months are allowed. In addition, this length of time may encourage market speculation as a means by which to "time" coming into compliance. Compliance instruments can be surrendered before verification occurs, and then adjustments can be made, if verification results in a change to the reported emissions. (SCAQMD4)

Comment: In the 15-day changes, ARB proposes to extend the deadline to surrender compliance instruments from six weeks to five or seven months. We do not understand why such a long period of time is needed, and believe it will complicate enforcement later. We recommend that ARB retain the original language. (CAPCOA2)

> **Response:** We appreciate the commenters' concern with changing the deadline for the surrender of annual compliance obligations. However, we believe that this deadline strikes the appropriate balance between enforcement concerns and allowing entities sufficient time to meet all requirements and acquiring compliance instruments before meeting their annual compliance obligations.

E-84. Comment: In the previous version of the regulation, allowances issued in the year during which the compliance obligation is calculated were eligible to be used for compliance for emissions that accrued in the previous year. This provision was useful in that at the end of a compliance interval, it provided entities with the ability to use a small portion of allowances issued for the first year of the subsequent compliance period to cover emissions accrued in the previous year. We understand that the language of section 95856 was changed to clarify that all allowance vintages within a compliance period may be used for emissions accrued in that compliance period. However, this change also eliminated the end-of-compliance interval flexibility that was present in the previous version. Modify section 95856(b)(2) as follows:

> (2) To fulfill any compliance obligation, a compliance instrument must be issued from an allowance budget year within or before the year ~~for~~ during which the compliance obligation is calculated, unless:
>
> > (A) The allowance is from an annual budget year within the same compliance interval as the year for which the compliance obligation is calculated; or
> > (~~A~~B) The allowance was purchased from the Allowance Price Containment Reserve pursuant to section 95913; or
> > (~~B~~C) The allowance is used to satisfy an excess emissions obligation. (WPTF2)

> **Response:** We disagree. In our view, this would effectively allow borrowing to meet an annual compliance obligation. The three-year compliance periods are designed to allow flexibility, but we do not wish to extend that flexibility to annual compliance obligations. Given that annual compliance obligations are less than a third of an entity's emissions with a compliance obligation, it seems difficult to envision realistic scenarios when this constraint could pose undue financial hardship on complying entities.

E-85. Comment: Section 95856 delineates the protocols for timely surrender of compliance instruments for a compliance period. To fulfill the concept of having multiple year compliance periods, as well as to provide additional flexibility in the transition between compliance periods in certain circumstances, SMUD recommends specific changes to section 95856(b)(2). First, compliance instruments for any year during a compliance period should be eligible for surrender for any obligation in that compliance period. Otherwise, the Cap and Trade program inappropriately sets up a series of unexpected annual tranches within the expected compliance periods. Compliance periods are an appreciated mechanism to provide market flexibility to smooth out potential year by year conditions that can lead to a lack of balances between the compliance instruments needed in a year and the annual supply of those instruments. The annual compliance obligation is only 30 percent of verified emissions for the year, intended to ensure ongoing attention to compliance, not to establish an inflexible annual compliance structure. The annual obligation is well below the expected distribution of annual allowances, so allowing vintages within the compliance period to be used for compliance cannot disrupt the expected 'balance' between the need for and supply of compliance instruments on an annual basis. ARB can allow compliance flexibility among the years within a compliance period, establishing true compliance periods in the Cap and Trade program. Even then, however, and particularly with the initial two-year compliance period that results from the delay in the Cap and Trade, removing 2012 as part of the first compliance period, there may be adverse circumstances that invoke a need for additional flexibility as the market moves from one compliance period to another. SMUD does not support, in general, allowing borrowing between compliance periods, as we believe this may result in a lack of balance between the amount of compliance instruments available in early years and the amount needed for compliance, in effect causing delays in investments that may be needed to achieve compliance by 2020. However, adverse circumstances could cause allowance prices to spike in the last year of a compliance period, and then fall as a new compliance period affords additional flexibility. SMUD believes that a mechanism to smooth the change between the first and second compliance periods would be particularly beneficial to the market. Modify section 95856(b)(2) as follows:

> (2) To fulfill any compliance obligation, a compliance instrument must be issued from an allowance budget year within or before the ~~year~~ compliance period for which the compliance obligation is calculated, unless:
>
> (A) The allowance was purchased from the Allowance Price Containment Reserve pursuant to section 95913; ~~or~~
>
> (B) The allowance is used to satisfy an excess emissions obligation~~.~~; or
>
> (C) The compliance instrument is from vintage 2015 and is used for compliance for the first compliance period. (SMUD3)

Response: As explained in response to the previous comment, we disagree with the portion of this comment suggesting "year" be replaced with "compliance period." We also disagree with the second part of the comment suggesting creation of section 95856(b)(2)(C). We do not believe it is necessary or advisable to provide this extra flexibility for the first compliance period because it is just two years in duration.

E-86. Comment: SMUD appreciates the addition in section 95856(d)(3), which is intended to indicate that there is no annual compliance obligation in the same year as a triennial compliance obligation. SMUD recommends a slight language change for clarity. Modify section 95856(d)(3) as follows:

> (3) In years 2015, 2018, and 2021 there is no annual compliance obligation for the preceding year~~compliance period~~, only a triennial compliance obligation for the preceding compliance period. (SMUD3)

Response: We believe our modifications included with the first 15-day changes to the regulation are adequately clear.

E-87. Comment: Section 95856(b) governs the compliance instruments valid for surrender in the Cap and Trade program. SCE recommends that ARB clarify the language to indicate that a compliance entity wishing to retire allowances may use any compliance instruments available at that time. As currently written, it is unclear whether compliance instruments from the last year of a compliance period may be used to fulfill a compliance obligation from the first year of that period. For example, there is confusion as to whether a compliance instrument issued in 2014 could be retired at the end of the compliance period (e.g., 2015) to satisfy a 2013 emissions obligation. Modify section 95856(b)(2) as follows:

> (2) To fulfill any compliance obligation, a compliance instrument must be issued from ~~an~~ any allowance budget year up to and including the year during which the compliance obligation is calculated and surrendered, unless; (SCE3)

Response: We do not believe there is confusion. This comment suggests inserts “up to and including” where the regulation has “within or before” (which this comment omits). We believe that both phrases are equally clear and have the same meaning.

E-88. Comment: Section 95856(b) should be revised to eliminate undue restrictions on the compliance instruments that may be used to meet a surrender obligation. Section 95856(b)(2) appears to allow entities to use for compliance only allowances issued in or before the year in which the relevant emissions were emitted. This is too restrictive and diminishes the value of having triennial rather than annual compliance periods. The flexibility associated with a three year compliance period should be retained. Additionally, entities should be permitted to use compliance instruments issued during the year in which the compliance obligation is calculated, i.e., the year immediately following the end of the compliance period. That would mitigate the potential for sellers of allowances to demand an extortionate price for vintage allowances when an entity gets past the end of a compliance period and finds that he does not have enough compliance instruments to cover his compliance obligation. To meet a compliance obligation, entities should be allowed to use allowances that were issued during the compliance period in which the emissions occurred, during any previous years, and during the year in which the surrender is due. For example, for the annual compliance obligation due in November 2014 for 30 percent of 2013 emissions, an entity should be able to use allowances issued in 2013 or 2014. For the triennial compliance obligation due in November 2018 for emissions in 2015, 2016, and 2017, an entity should be able to use allowances issued in 2013, 2014, 2015, 2016, 2017, and 2018. Modify section 95856(b)(2) as follows:

> (2) To fulfill any compliance obligation, a compliance instrument must be issued from any allowance budget year up to and including ~~within or before~~ the year in~~for~~ which the compliance obligation is calculated and surrendered, unless: ... (SCPPA6)
>
> **Response:** We disagree. As noted in the response to the previous comment, we do not see a difference between "up to and including" and "within or before." The recommendation to allow "and surrendered" would effectively allow borrowing from the current compliance period to meet the obligation from the past compliance period. Our policy decision is not to allow such borrowing.

E-89. Comment: The treatment and use of vintage allowances, combined with the aforementioned market rules greatly increase concerns around liquidity and market confidence—especially at the end of a compliance period. As written, a significant percentage of allowances will be unavailable for trading in closing months of a compliance period due to the compliance accounts, holding limits and annual surrender. In the months preceding final true-up, compliance entities will be aware of the fact that they must hold enough of the proper vintage allowances in order to meet their final true up (for this first compliance period, this will mean vintages 2013 and 2014). This will cause many compliance entities to conservatively bank the proper vintages, leading to little allowance availability, greatly reduced liquidity and a potential crisis in market confidence during the 2015 true-up period. These problems could be exacerbated by parties without a compliance obligation that bank and carry over allowances. During this time, compliance entities will have in hand 2015 vintage allowances, allocated early in 2015. Unfortunately, the Regulation as written prohibits use of these allowances for use in 2015 true-up for the 2012-2014 compliance period. In order to increase allowance availability, liquidity and market confidence, the Regulation should prohibit non-compliance entities from carrying allowances across compliance periods and should allow use of vintages that correspond to the year in which the surrender must be made—as well as earlier vintages. A simple change here could greatly increase flexibility, allowance availability and market confidence. Section 95856(b)(2) should read:

> To fulfill any compliance obligation, a compliance instrument must be issued from an allowance budget year within or before the year during which the compliance obligation is to be surrendered ~~calculated~~, unless: (BP2)

Response: As noted in the response to the previous comment, allowing allowances of the vintage year in which allowances are to be surrendered is effectively to allow borrowing. Our policy decision is not to allow such borrowing.

Untimely Surrender, Section 95857

E-90. Comment: The excess emissions obligation is four times the shortfall and must be satisfied by purchasing allowances from the auction or allowance reserve sale following the due date of the triennial compliance obligation. To protect against the inappropriate penalizing of covered entities meeting their obligations in a timely manner, ARB should not remove all of the allowances needed to satisfy the excess emissions obligation from the auction or price containment reserve. Instead, ARB should require the entity subject to the shortfall to obtain the allowances that it is short for meeting its compliance obligation (i.e. 1/4 of the excess emissions obligation), thereby maintaining the integrity of the "cap." On the other hand, the same entity should be required to meet the rest of the penalty (i.e. 3/4 of its excess emissions obligation) via a financial payment, based on the auction clearing price, yet disconnected from direct participation in an auction per se. Modify section 95857(b) as follows:

(b) Calculation of the Untimely Surrender Obligation.

(1) The quantity of excess emissions is the difference between the compliance obligation calculated pursuant to this section and any compliance instruments timely surrendered by the entity;

(2) The <u>value of an</u> entity's compliance obligation for untimely surrender is calculated as four times the entity's excess emissions;

(3) An entity's compliance obligation for untimely surrender may only be fulfilled with CA GHG allowances<u>,</u> or allowances issued by a GHG ETS pursuant to subarticle 12, <u>or through the financial penalty specified in subsection 95857(b)(5) below</u>; and

(4) The untimely surrender obligation is due within five days of the first auction or reserve sale conducted by ARB following the applicable surrender date, whichever is the latter, and for which the registration deadline has not passed when the untimely surrender obligation is assessed.

<u>(5) For each entity with an untimely surrender obligation, the entity shall enter the auction and procure 1/4 of the allowances needed to satisfy the untimely surrender obligation. In addition, 3/4 of the untimely surrender obligation will be paid to CARB in the form of a financial penalty equal to the auction clearing price and will be allocated to the Air Pollution Control Fund.</u> (IEPA2)

Response: This comment falls outside the scope of the first 15-day changes to the regulation, which did not consider whether an untimely surrender obligation should be met through extra allowances or a financial penalty. Moreover, this comment is based at least in part on a couple of faulty premises. First, the comment assumes that allowances will be available only via auction or the price containment reserve. We expect there will also be allowances available on the secondary market. Second, the comment cites the need for certain vintage allowances to be available in the price containment reserve. However, the regulation provides that allowances of any vintage from the price containment reserve may meet a compliance obligation. No further response is required.

E-91. Comment: The relationship between sections 95857, 95858, and the enforcement provisions of the Mandatory Reporting Regulation is not clear. It appears that an entity could be penalized twice for the same infraction. We recommend that ARB clarify the linkages between the Regulations, and make it clear that an entity is penalized only once for a legitimate violation. In section 95857(b)(1) the quantity of excess emissions is calculated and in (4) it states when the untimely surrender obligation is due. However, it appears this section is missing a notification step between the calculation and the time of the surrender. If the notification step needs to be added or is in another provision, we recommend that ARB clarify this in this subsection. In section 95857, the entity's compliance obligation for untimely surrender is calculated as four times the entity's excess emissions, and the consequence of not meeting that obligation is set out in new subsection (c). It includes in the calculation a reference to the number of violations under section 96014. In section 96014(b) it states that a separate violation can be for each day or portion thereof after the end of the Untimely Surrender Period that each required compliance instrument has not been surrendered. The impact of these new revisions to both sections appears to be excessive. (CACC2)

Response: We agree with the need for clarification, and we replaced the text previously in section 96014(b) with this new text: "A separate violation accrues every 45 days after the end of the Untimely Surrender Period for each required compliance instrument that has not been surrendered." We evaluated the language in this Regulation and the MRR and do not believe there is a new "layering" of penalties between the two regulations.

E-92. Comment: While the untimely surrender obligation will be calculated only once per annual and triennial obligation, violations are still accrued daily. In ARB's earlier discussion Draft, released July 7, 2011, this section had been edited to calculate violations per 45 day period. Those edits have been removed from the July 2011 proposed Modifications. SCE supports the discussion Draft language and recommends that ARB revert to the 45-day period calculation. (SCE3)

Response: We agree, and in the second 15-day changes to the regulation included new text in section 96014(b) implementing the 45-day calculation.

E-93. (multiple comments)
Comment: We recommend a shorter time period for the surrender of additional compliance instruments that are owed as a penalty for untimely surrender. Currently, with the extension in the original deadline to surrender, the penalty is not due until over a year after the compliance period ends. (CAPCOA2)

Comment: Making up excess emissions at a 4:1 ratio (section 95857) is a good deterrent. However, the rules are structured so that this is not due until five days after the next auction or reserve sale conducted by CARB. This presumes that these will be the only mechanisms for market participants to obtain compliance instruments and may introduce unnecessary delays in obtaining the make-up compliance instruments. We suggest that the excess emissions be due in 30 days, and then appropriate additional enforcement action can be taken for delays. (SCAQMD4)

Comment: Regarding section 95857(b)(4), an untimely surrender obligation is due within five days of the first auction or reserve sale conducted by ARB following the applicable surrender date, whichever is later. We recommend whichever is earlier, instead of later. (SCAQMD4)

> **Response:** We disagree, recognizing that the covered entities may need additional time to acquire allowances of a certain vintage, particularly if there is limited supply of such allowances in the secondary market.

E-94. Comment: NCPA submits that five days is still an insufficient amount of time for entities to complete the necessary administrative functions that will accompany the purchase and surrender of allowances, and that section 95857(b)(4) allow two weeks (or 10 business days) to complete the transaction. (NCPA3)

> **Response:** We disagree. We believe that five days is sufficient.

E-95. Comment: MSCG has argued that assessing a requirement to surrender incremental allowances in cases of untimely surrender is not good policy design, as it raises the compliance costs for non-offenders. ARB's proposal to transfer such incremental allowances to the Auction Holding Account instead of the Allowance Price Containment Account Reserve (section 95857(d)(1)), as previously proposed, effectively remedies this defect, and we commend the ARB for this change. (MSCG3)

> **Response:** Thank you for supporting this modification.

E-96. Comment: The provision in section 95857(c) appears to mean that if an entity with an untimely surrender obligation in fact satisfies that obligation, then it will not be subject to any additional civil or criminal penalties for the untimely submittal of its original compliance obligation. This provision may provide insufficient deterrence and may lead to a facility deliberately failing to comply in a timely manner while compliance instrument prices may be relatively high and postponing its obligations until later, when prices may be lower. In RECLAIM, we have seen prices drop dramatically after the conclusion of the reconciliation period. The price differential may be enough to make up for the obligation being multiplied by four times. We recommend retaining the ability to impose civil or criminal penalties for untimely surrender. (SCAQMD4)

Response: We believe that program design features address this issue. We have an auction reserve price that begins at $10 in the first year of the auction and escalates through 2020. We believe that this measure will deal with potential oversupply conditions and keep the market price above $10. Therefore, we are confident that any excess emissions obligation would result in at least a $30 per ton cost increase for the violator.

E-97. Comment: Staff supports the deletion of section 95857(c)(6) that would have precluded enforcement action if the untimely surrender obligation was not met in 30 days. CARB should retain discretion to handle such matters on a case-by-case basis. (SCAQMD4)

Response: Thank you for supporting this modification.

E-98. Comment: Sections 95831 and 95857 seem to conflict. The language in section 95831(b)(4) "allowances submitted to fulfill an entity's excess emissions obligation" refers to the three fourths portion of the untimely surrender obligation to be transferred to the Auction Holding Account pursuant to section 95857(d). Section 95857(d) has the same amount being deposited in a different place—the Auction Holding Account. This conflict can be resolved either of the following two ways depending on which account these allowances are directed to. The first would result in placing the three fourths portion in the Allowance Price Containment Reserve Account and the second would result in placing it in the Auction Holding Account. Modify section 95831(b)(4)(C) and 95857(d)(1)(A) as follows:

(C) Into which three fourths of the serial numbers of allowances submitted to fulfill an entity's untimely surrender ~~excess emissions~~ obligation pursuant to section 95857 (a) through (c) ~~(d~~) will be transferred; and

(A) Three fourths to the Allowance Price Containment Reserve ~~Auction Holding~~ Account; and

Or modify section 95831(b)(4)(C) and 95831(b)(2) as follows:

~~(C) Into which the serial numbers of allowances submitted to fulfill an entity's excess emissions obligation pursuant to section 95857(d) will be transferred; and~~

(D) Three fourths of allowances used to fulfill facilities' untimely surrender obligation pursuant to sections 95857(a) through (c), as described section 95857(d). (SCAQMD4)

Response: We agree and modified the regulation accordingly. We deleted the text in section 95831(b)(4)(C) and added a new section 95831(b)(2)(D).

E-99. Comment: Section 95831(b)(4)(C) provides for allowances “submitted to fulfill an entity’s excess emissions obligation pursuant to section 95857(d)” to be placed into the Allowance Price Containment Reserve Account. However, as a very welcome change from the Discussion Draft, section 95857(d)(1)(A) now provides for three fourths of those allowances to be transferred to the Auction Holding Account. Accordingly, Section 95831(b) should be revised as follows to reflect this change in the disposition of penalty allowances. Modify section 95831(b) as follows:

> (b) Accounts under the Control of the Executive Officer. The accounts administrator will create and maintain the following accounts under the control of the Executive Officer:
>
> > (2) A holding account to be known as the Auction Holding Account into which allowances are transferred to be sold at auction from: ...
> >
> > > (D) The Executive Officer pursuant to section 95857(d)(1)(A), being three fourths of the allowances submitted to fulfill an entity's excess emissions obligation.
> >
> > (4) A holding account to be known as the Allowance Price Containment Reserve Account:
> >
> > > (A) Into which the serial numbers of allowances allocated by ARB for auction that remain unsold at auction will be transferred;
> > > (B) Into which the serial numbers of allowances directly allocated to the Allowance Price Containment Reserve pursuant to section 95870(a) will be transferred; and
> > > ~~(C) Into which the serial numbers of allowances submitted to fulfill an entity's excess emissions obligation pursuant to section 95857(d) will be transferred; and~~
> > > (C~~D~~) From which the Executive Officer will authorize the withdrawal of allowances for sale to covered entities pursuant to section 95913. (SCPPA6)

> **Response:** We agree with this comment. We added text in a new section 95857(b)(2)(D) similar to that suggested in this comment. We deleted the text previously in section 95857(b)(4)(C).

E-100. Comment: SMUD points out that section 95831(b)(2)(B) should refer to 95921(f)(3) rather than 95921(e)(3). Modify section 95831(b)(2)(B) as follows:

> (B) The holding accounts of those entities for which allowances are being auctioned on consignment pursuant to section 95921(f~~e~~)(3). (SMUD3)

> **Response:** Section 95831(b)(2)(B) does refer to section 95921(f)(3).

E-101. Comment: HDPP supports the proposed modification to delay the commencement of the initial compliance obligation from 2012 to 2013. A delay of the compliance obligation to 2013 is needed to ensure that the Cap and Trade Rule is implemented properly without glitches that could adversely affect program participants, power markets, and the economy. It is also required to meet AB 32's mandate that any ARB regulations be designed "in a manner that minimizes costs and maximizes benefits for California's economy, improves and modernizes California's energy infrastructure and maintains electric system reliability, maximizes additional environmental and economic co-benefits for California, and complements the State's efforts to improve air quality" (Cal. Health & Safety Code, section 38501(h); see also sections 38560, 38661(a), 38562(a), 38562(b)(1)). (HDPP4)

Response: Thank you for supporting this modification.

E-102. Comment: SCE requests additional clarification on section 95857(b)(4), which addresses the due date of the untimely surrender obligation. In the current language, this obligation is due five days after "the first auction or reserve sale conducted by ARB following the applicable surrender date, whichever is the latter, and for which the registration deadline has not passed when the untimely surrender obligation is assessed." This language is confusing and should be clarified. SCE reads "the applicable surrender date" to be the annual or triennial compliance due date. As this deadline is now November 1 for all entities and all compliance obligations, it seems unnecessary to have this complex calculation. For instance, the provision could retain the exact same deadline outcome if it instead stated that the obligation is due "the 17th business day of the first month of the quarter" (or five days after the auction). SCE requests that ARB clarify these provisions to provide certainty to regulated parties. (SCE3)

Response: We acknowledge the commenter's concern for clarity. Since there is some possibility that the schedule of auctions could change to become more or less frequent, we left this provision in the regulation more general, so that it might more readily adapt to any future changes in the auction schedule. Our current text also allows complying entities more flexibility than the alternative suggested in this comment. We will also notify parties of specific dates based on the criteria in the Regulation if they are subject to these provisions.

E-103. Comment: SMUD appreciates the changes in the untimely surrender requirements included in the 15-day language. However, some additional changes would add clarity to how the untimely surrender requirement works, provide for a clear opportunity to procure and surrender the excess emissions requirement, and make clear exactly when a regulated party may have basic surrender violations subject to Health and Safety code penalties. Although not strictly a "penalty" provision, the operation of the untimely surrender obligations has significant interaction with the violation and penalty structure in the Cap and Trade program. First, SMUD notes that the term "within" in the regulation could be interpreted to be either before or after the events mentioned, and believes that the intent is "after." Second, SMUD suggests that a regulated party subject to untimely surrender be afforded the opportunity to procure allowances in both a regular auction or a reserve sale, not one or the other. In most circumstances, the first regular auction will present an opportunity to procure allowances at market prices, leaving it unnecessary to consider the higher priced allowances in the reserve sale. However, in the circumstance that allowances are not available in the auction or are not well-priced, the reserve sale would provide a final opportunity for compliance prior to being subject to penalties. Accessing both events may be intended by the "whichever is the latter" language, but SMUD believes the intent could be clarified. Finally, SMUD believes that ARB should clarify further what happens when an entity fails to surrender the untimely obligation as required, so that a double violation is not implied. Modify sections 95857(b)(4) and 95857(c)(2) as follows:

> (4) The untimely surrender obligation is due ~~within~~ five business days after the occurrence of the first auction ~~or~~and first reserve sale conducted by ARB following the applicable surrender date~~, whichever is the latter~~, and for which the registration deadline has not passed when the untimely surrender obligation is assessed.
> (2) If a portion of the untimely surrender obligation is not surrendered as required, the entity will have a new untimely surrender obligation (replacing the previous surrender obligation calculated under section 95857(b)(2)) equal to the amount of the previous untimely surrender obligation which was not satisfied by the deadline stated in section 95857(b)(4) upon which the number of violations will be calculated pursuant to section 96014. The new untimely surrender obligation is due immediately; and (SMUD3)
>
> **Response:** Thank you for supporting our previous modifications. We believe the test accurately and clearly reflects our policy. We also disagree with the need to change "five days" to "five business days."

E-104. (multiple comments)
Comment: In section 95857(c), the modified text adds new language regarding recalculation of the obligation for failure to submit the full amount. NCPA proposes revisions consistent with the Joint Utilities that clarifies the fact that this recalculation is a new obligation, and not in addition to the entity's original obligation. Modify section 95857(c) as follows:

> (c) If an entity with an untimely surrender obligation fails to satisfy the obligation pursuant to section 95857(b)(4), then:
>> (1) ARB will determine the number of violations pursuant to section 96014;
>> (2) If a portion of the untimely surrender obligation is not surrendered as required, the entity will have a new untimely surrender obligation (replacing the previous surrender obligation calculated under section 95857(b)(2)) equal to the amount of the previous untimely surrender obligation which was not satisfied by the deadline stated in section 95857(b)(4) upon which the number of violations will be calculated pursuant to section 96014. The new untimely surrender obligation is due immediately. (NCPA3)

Comment: Section 95857(c)(2) should be clarified to make it clear that the "new untimely surrender obligation" replaces and is not additional to the previous untimely surrender obligation. In addition, the purpose of section 95857(c)(3) is unclear. It states that the calculation of the untimely surrender obligation shall only apply once, but the preceding section (2) specifies a second, “new” surrender obligation. If the purpose of section (3) is to clarify that the “new” surrender obligation replaces the previous one, we suggest the following language. Modify section 95857(c) as follows:

> (c) If an entity with an untimely surrender obligation fails to satisfy the obligation pursuant to section 95857(b)(4), then:
>
> > (1) ARB will determine the number of violations pursuant to section 96014;
> >
> > (2) If a portion of the untimely surrender obligation is not surrendered as required, the entity will have a new untimely surrender obligation <u>(replacing the previous surrender obligation calculated under section 95857(b)(2))</u> equal to the amount of the previous untimely surrender obligation which was not satisfied by the deadline stated in section 95857(b)(4) upon which the number of violations will be calculated pursuant to section 96014. The new untimely surrender obligation is due immediately; and
> >
> > (3) The calculation of the untimely surrender obligation shall only apply once for each untimely surrender of compliance instruments per annual or triennial compliance obligation. (SCPPA6)

> **Response:** The modification suggested in these comments is the same as one of the suggestions in the previous comment. No further response is required.

E-105. (multiple comments)
Comment: We appreciate the changes staff made in section 95857(d)(1)(a) where three-fourths of allowances for an untimely surrender will be moved to the Auction Holding Account instead of the Allowance Price Containment Reserve. The change will ensure that compliant facilities will not be penalized by higher allowance prices due to allowances being removed from the auction and placed in the higher priced Reserve. (CCGG2)

Comment: SMUD appreciates the change in the 15-day language that allowances associated with the excess emissions obligation under the untimely surrender provisions (section 95857(d)) are now transferred to the Auction Holding Account rather than the Containment Reserve Account. (SMUD3)

Comment: SCE strongly supports the change in section 95857(d)(1)(a), which places excess emissions allowances paid as penalties back into the market through the next quarterly auction, rather than in the Allowance Reserve. Placing the penalty allowances into the Allowance Reserve would impose an additional marginal cost increase on the rest of the regulated community that had nothing to do with the original penalty. (SCE3)

> **Response:** Thank you for supporting this change.

E-106. Comment: Section 95857(c)(2) appears to be duplicative. If an entity fails to timely surrender allowances, then the penalties should be imposed on the amount that was not surrendered. This provision also refers to section 96104 which would apply a daily violation for each compliance instrument not surrendered by the end of the Untimely Surrender Period. Modify section 95857(c)(2) as follows:

> ~~(2) If a portion of the untimely surrender obligation is not surrendered as required, the entity will have a new untimely surrender obligation equal to the amount of the previous untimely surrender obligation which was not satisfied by the deadline stated in section 95857(b)(4) upon which the number of violations will be calculated pursuant to section 96014. The new untimely surrender obligation is due immediately; and~~ (LADWP4)
>
> **Response:** We disagree with the specific suggestion to delete the text in section 95857(c)(2), and do not believe it is duplicative. However, we believe we addressed the commenter's concern by changing the text in section 96104(b) from a new violation each day to a new violation every 45 days.

Under-Reporting, Section 95858

E-107. (multiple comments)
Comment: ARB has proposed to add a new section 95858 regarding compliance obligations for under-reported emissions in a previous compliance year. WSPA supports ARB's approach of requiring the surrender of additional compliance instruments only if the under-reporting exceeds five percent of the originally reported emissions. WSPA also believes that a facility's potential obligation to surrender compliance instruments for a previous compliance period should be subject to a reasonable time limit. (WSPA3)

Comment: We agree with the concept that allowance shortfalls resulting from under-reporting for previous compliance periods should be corrected by the surrender of additional allowances, to the extent that the shortfall exceeds five percent of the original compliance obligation. We request clarification to specify that penalties would not be imposed under the Cap and Trade rule if the additional allowances are surrendered in accordance with this section, and to add a five year limitations period so that covered entities are not liable for potential shortfalls in perpetuity. Modify section 95858 as follows:

> If, after an entity has surrendered its compliance instruments for a compliance period pursuant to section 95856, the Executive Officer determines, through an audit or other information, that the entity under-reported its emissions under MRR for any emissions sources that form the basis for the <u>entity's</u> compliance obligation, then the following shall apply:
>
> > (a) If <u>EMd - CO ≤ 0.05CO, then the entity is not required to take any further action.</u> ~~the difference between the emissions used to calculate the compliance obligation and subsequently used to calculate the number of compliance instruments surrendered pursuant to section 95856 and the emissions determined by the Executive Officer to be under-reported for the sum of those emissions is less than five percent, then the entity is not required to take any further action.~~

(b) If ~~the difference between the emissions used to calculate the compliance obligation and subsequently calculate the number of compliance instruments surrendered pursuant to section 95856 and the emissions determined by~~EMd CO > 0.05CO, then upon the receipt of notice from the Executive Officer ~~to be under-reported for the sum of those emissions is more than five percent, then~~ the entity must surrender additional compliance instruments for the previous compliance period in the following amount

Cla= Emd – CO – (CO * 0.05)

~~Where:~~

(c) Not later than six months from the date the entity receives notification from the Executive Officer that the entity must surrender additional compliance instruments due to under-reported emissions for a previous compliance period, the entity shall surrender the quantity of compliance instruments determined in accordance with subsection (b). The provisions of section 95857 shall not apply and the entity shall not be subject to penalties under this Article if the additional compliance instruments are surrendered during the six month period. The entity may use compliance instruments from subsequent compliance periods to meet this surrender obligation.

(d) For the purposes of this section: 'Cla' is the number of additional compliance instruments that must be surrendered to ARB ~~to cover under-reported emissions~~in accordance with this section; 'CO' is the ~~emissions number used to determine the~~quantity of compliance ~~obligation~~instruments surrendered pursuant to section 95856 ~~for any~~to meet the entity's compliance obligation for the previous compliance period; and 'EMd' is the ~~number of the~~entity's corrected total emissions for the previous compliance period, determined by the Executive Officer ~~for the sum of the emissions sources subject to a compliance obligation;~~.

~~(c) The entity will have six months from the time of notification by the Executive Officer to surrender additional compliance instruments for under reporting emissions under MRR as determined pursuant to this section. The provisions of section 95857 shall not apply during these six months. The entity may use compliance instruments from subsequent compliance periods to meet these requirements. The entity may only use CA GHG allowances or allowances issued by a GHG ETS approved pursuant to subarticle 12 to meet the requirements of this section.~~

(e) Any determination that an entity under-reported its emissions for a previous compliance period shall be made by the Executive Officer no later than five years from the deadline for submission to the Executive Officer of the verified emissions data report for that compliance year. (PGE4, WSPA3, CCEEB3)

Response: We agree at least in part with this comment. We added the term "entity's" in the first paragraph and we added the new text suggested in this comment for a new section 95858(e), except that our modification provided for a period of eight year instead of five years. We did not make the other modifications suggested in this comment as they did not seem necessary to clarify the intent.

E-108. Comment: New section 95858, "Compliance Obligation for Under-Reporting in a Previous Compliance Period," was added to address cases when the Executive Officer finds there has been under-reporting by an entity after it has submitted compliance instruments to meet its compliance obligation. CARB states that these provisions are necessary so entities with a compliance obligation know what action the Executive Officer will take in the event they are found to have under-reported their emissions. However, the language included in section 95856 states that the Executive Officer can determine through an audit or other information that an entity has under-reported its emissions. This lacks sufficient definition to ensure a regulated entity understands what information the Executive Officer will be basing their determination on to be able to conduct effective self-audits for the purpose of compliance demonstration. (VALERO2)

Response: We disagree. We believe the regulation provides sufficient definition. The MRR also contains the specific monitoring, reporting, and record retention requirements that could be the basis for a covered entity to develop a self-audit plan.

E-109. Comment: In the newly proposed section 95858, if a facility that has already surrendered its compliance obligation (in a previous compliance period) is discovered to have under-reported its emissions by less than five percent of its total emissions, there is no obligation to surrender additional compliance instruments to make up for the emissions difference. However, for the State's largest emitters between 3 and 4 million tons per year (three facilities), or between 4 and 5 million tons of emissions per year (three facilities), five percent underreporting may amount to 150,000 to 250,000 tons of CO_2e emissions. By comparison, 250,000 tons is more than the total emissions of about half of the proposed regulated stationary sources covered by the Cap and Trade program. A facility with 1 million tons of emissions (about 30 in all within California) would only have to under-report by roughly 2.5 percent to exceed the 25,000 metric ton threshold by which all other facilities become subject to the regulation. Since emissions verification is based on a targeted risk-based procedure and does not require each and every source of emissions at a covered facility to be validated, the derivation of a percentage value for the amount of emissions that is underreported at a facility cannot be deemed wholly accurate with regards to the facility emissions report as a whole. It strikes EDF as improper to assign a one-size-fits-all value to what constitutes acceptable under-reporting. EDF recommends CARB reexamine whether the five percent threshold in section 95858 is appropriate for California's largest facilities (such as those that emit greater than one million tons annually). The amount deemed to be underreported is likely to exceed 25,000 tons of CO_2e per year if the underreported percentage is only 2.5 percent, half of the proposed limit. Accordingly, EDF recommends CARB consider modifying section 95858 to apply the five percent limit to facilities with less than one million tons of emissions a year on average, and a

2.5 percent limit to facilities with greater than one million tons of annual emissions. (EDF4)

> **Response:** Five percent is the threshold for material misstatement in the MRR. Section 95858 uses that same threshold, as it would not make sense to have a smaller threshold in section 95858 than in the MRR.

E-110. Comment: We do not support having no compliance obligation for up to five percent under-reporting. If this is not changed we suggest the following. Because there is no violation unless the five percent threshold is exceeded, program participants will argue that the number of violations is limited to the number of compliance instruments which exceed five percent. The rule should make it clear that, once the five percent margin is exceeded, every compliance instrument, even those within the five percent margin, will be counted as the basis for a separate violation. (SCAQMD4)

> **Response:** We disagree. We believe the regulation was clear that the number of additional compliance instruments to be surrendered is only for those emissions exceeding the five percent margin. The provisions for under-reporting do not undermine the requirements for true, accurate, and complete reporting under the MRR.

E-111. Comment: In section 95858(a) we are concerned that the provision of a five percent "free" under-reporting will introduce a potentially significant failure of the market to reach its required goals. The Mandatory Reporting Rules also allow up to three percent of emissions (up to 20,000 MT CO_2e) to be considered "de minimus" with less rigorous reporting requirements, which also compounds this potential problem. (SCAQMD4)

> **Response:** We believe the concern for a “significant failure” is overstated. The five percent for material misstatement is a widely used threshold in other regulatory and voluntary GHG reporting programs. The de minimus threshold strives to strike a balance between accurate reporting and cost-effective reporting for smaller sources within a covered entity.

E-112. Comment: The formula in section 95858(b) does not represent an adequate deterrent against under-reporting. Under-reported emissions should also be made up at a 4:1 ratio, if a shortfall occurred, regardless of whether it was from under-reporting or not surrendering enough compliance instruments to cover reported emissions. Six months is also too long to make up the shortfall. This should be shortened or let to CARB discretion considering the amount of emissions due. (SCAQMD4)

> **Response:** We disagree. The penalty provisions under the MRR provide a very strong deterrent for under-reporting.

E-113. Comment: In section 95858(c) it is unclear why "subsequent" year compliance instruments are usable for correcting under-reporting, when they are not usable for the original obligation. This could encourage facilities to deliberately under-report emissions. At a minimum, we suggest that the "subsequent" years be limited to the year in which the under-reporting obligation is being satisfied. (SCAQMD4)

> **Response:** We disagree. We wish to provide entities more flexibility for addressing underreporting shortfalls, especially when they are ensuring the environmental integrity of the program after the compliance period has ended.

E-114. Comment: WPTF has previously raised concerns that the penalties for failure to surrender sufficient compliance instruments were overly punitive and would raise costs of allowances for other compliance entities. WPTF remains concerned that the modified regulation now provides for the possibility that CARB may audit an entity's data emission reports after those reports have been verified, to determine if emissions for a compliance period have been under-reported, and retroactively hold that entity responsible for surrendering additional compliance instruments to make up the deficiency. WPTF considers the provisions of this section to be completely inappropriate. Once a covered entity's emissions data report has been verified by an accredited verifier, the covered entity should be able to rely on that report and surrender compliance instruments based on it without a threat that a future audit will create an additional compliance obligation and the possibility of compliance penalties. This potential recalculation of the compliance obligation based on a separate audit is essentially subjecting capped entities to "double-jeopardy," and holding them responsible for errors by third-party verifiers. WPTF does not object to auditing of emission reports, but the goal of these audits should be to monitor the performance of verifiers. Any errors found in emission reports should factor into verifiers' ongoing accreditation, but should not result in consequences to the entities that have used that verifier. The entirety of section 95858 should be deleted. (WPTF2)

> **Response:** We disagree with this comment and believe section 95858 is essential to ensuring the program's environmental integrity.

F. CO-POLLUTANTS

F-1. ARB's public workshop notice states that, "Staff is also investigating ways to ensure that large industrial sources subject to the recently finalized Energy Efficiency and Co-Benefits Audit regulations be required to take all cost-effective action identified under those audits." It appears that ARB is now proposing to make implementation of the audit recommendations a requirement, subject to penalties, for facilities that are also subject to the Cap and Trade program. LADWP recommends that this separate, but very closely related and important regulation, be publicly vetted in a separate public comment period and workshop from this specific 15-Day Modified Text comment period. The draft regulation that is currently being publicly reviewed does not include any provisions that relate to the Energy Efficiency and Co-Benefits Audit regulation. LADWP recognizes the importance of ensuring that the ARB consider the potential for direct, indirect, and cumulative emission impacts from the Cap and-Trade program on communities that are already adversely impacted by air pollution. LADWP requests that ARB give full time and consideration to any amendments of the Energy Efficiency and Co-Benefits Audit regulation without the restrictions of this current 15-Day rulemaking comment period. (LADWP4)

> **Response:** Any changes made to the Energy Efficiency and Co-benefits Assessment Regulation for Large Stationary Sources, or to directly require GHG reductions at large industrial sources, will be made during a separate rulemaking process, and will have its own public comment period, as suggested by the commenter.

F-2. (multiple comments)
Comment: ARB should require an ongoing review and update of the co-pollutant emissions assessment included in the Initial Statement of Reasons, and should continue to work with the Department of Public Health in ongoing review and evaluation of the impacts of the Cap and Trade program. We understand that mitigation of environmental impacts resulting from the Cap and Trade rule is expected to rely on an adaptive management approach, which in turn will depend in part upon the information collected to assess impacts resulting from permitting offsets of ongoing emissions rather than modifications to reduce emissions at a given emitter. It is important that ARB include a regular review of the data it collects to determine what exposures are being perpetuated, if any at local and regional scales. These reviews should also include new scientific information, findings or methods that could enhance the analysis and understanding of the impacts of emissions on surrounding communities. In addition, these reviews should be accompanied by an opportunity for review and input by outside experts and members of the public. (SIERRACLUBCA5)

Comment: We recommend the identification of information about trading activity that can be monitored to indicate if an increase of emissions is likely to occur. That is, indicators of market or permit activity (both at 1 for the purpose of this letter, the “identified impact level” is the value of an indicator or metric that, when reached, means an impact has been observed and some adaptive action will be taken by CARB or other agency with jurisdiction. The macro-scale and at a localized neighborhood scale) that would lead the regulator to believe that emissions may be increasing in the near future (prior to those emissions actually increasing) both in environmental justice communities and non-environmental justice communities. (EDF5)

Comment: We recommend the identification of metrics that should be tracked that are necessary to understand whether deleterious impacts on public health are occurring, both in environmental justice communities and non-environmental justice communities. (EDF5)

Comment: We recommend the identification of steps that can be taken, established as a hierarchy of action, for preventative and responsive action planning for public health and air quality protection. Existing adaptive management strategies identified in the regulatory documents should be included in addition to new measures. Prioritizing strategies based on the degree of observed harm or impact level should be considered within this approach. (EDF5)

> **Response:** Although we anticipate that co-pollutant emissions would decrease under the cap-and-trade program, we are committed to monitoring the implementation of the regulation to identify and address any situations where the program results in an increase in criteria air pollutant or toxic emissions. In Resolution 11-32, the Board approved an adaptive management plan for the cap-and-trade program.
>
> At least once each compliance period, we would use information collected through the mandatory reporting regulation, the cap-and-trade regulation, and other sources of information to evaluate how individual facilities are complying with the cap-and-trade regulation. The public will have ample opportunity to comment on these assessments. At least once a compliance period we will update the Board on the adaptive management plan. Where necessary, we will consult with CDPH and outside experts. We do not believe that tracking specific public health outcomes will provide data that will be useful to the adaptive management plan because many health impacts are not observed until years after exposure occurs and due to the low levels of exposure anticipated it would be difficult to observe a significant association, and extremely challenging to establish causation.
>
> If adverse co-pollutant impacts are identified and can be attributed to the cap-and-trade regulation, we are committed to promptly developing and implementing appropriate responses through a public process, including consideration and approval by the Board as necessary.

F-3. (multiple comments)

Comment: One serious flaw is that ARB's rules allow some of California's biggest polluters to meet the vast majority of cumulative reductions from business-as-usual pollution reductions through 2020 through the purchase of carbon offset credits, which can come from outside California and eventually from outside the United States. Such offset loopholes deprive California of the environmental, economic, and public health co-benefits that a carbon cap purportedly provides. (FRIENDSOFEARTH3)

Comment: Research shows that out-of-state offsets will increase criteria pollution. (David Roland-Holst, “Carbon Emission Offsets and Criteria Pollutants: A California Assessment,” March, 2009, University of California, Berkeley.) Air pollution is worst in low-income communities and communities of color, such as the neighborhoods downwind from oil refineries in the LA area. We call upon ARB to eliminate out-of-state offsets and greatly reduce the allowed in-state offsets. It is embarrassing that over 85 percent of the GHG reductions could come from offsets. Relieve low-income communities and communities of color from this heavy burden. (EDLA)

Comment: Continued reliance on offsets undermines environmental integrity and endangers local communities. The current rulemaking package fails to ensure that activities undertaken to comply with the regulations do not disproportionately impact low-income communities. A University of California study looked at six types of air pollutants and found that under a scenario which allows 50 percent of offsets to be sourced out of state, California’s air pollution would actually increase in five out of six pollution categories. (FRIENDSOFEARTH2)

> **Response:** The commenters reference a University of California (UC) Berkeley study which they state demonstrates that allowing out-of-state offsets in the program would increase co-pollutant emissions in California. Contrary to the commenters’ concerns, the facilities’ ability to use offsets that originate outside of California will not cause an increase in co-pollution emissions in California. The UC Berkeley study found that if all facilities only purchased out-of-state offsets, then the potential co-pollutant benefits realized by a greenhouse gas cap-and-trade program would be less than if no offsets were allowed. This finding should not be misinterpreted to imply that out-of-state offsets would lead to an increase in co-pollutant emissions in California.
>
> Furthermore, as stated in the response to comments for the Staff Report, numerous studies have evaluated the potential for inequitable impacts from emissions trading programs on minority neighborhoods, racial and ethnic groups, and general community demographics, and found that trading did not have a disproportionate impact.
>
> The most effective way to reduce the impacts of co-pollution emissions in low-income and disadvantaged communities is to implement programs that target reductions in co-pollutant emissions directly. While a GHG-focused program would likely reduce co-pollutant emissions along with GHG emissions, it is not the most effective mechanism for decreasing exposure to co-pollutants.
>
> Although we anticipate that co-pollutant emissions would decrease under the cap-and-trade program, we are committed to monitoring the implementation of

the regulation to identify and address any situations where the program results in an increase in criteria air pollutant or toxic emissions. In Resolution 11-32, the Board approved an adaptive management plan for the cap-and-trade program.

At least once each compliance period, we would use information collected through the mandatory reporting regulation, the cap-and-trade regulation, and other sources of information to evaluate how individual facilities are complying with the cap-and-trade regulation. The public will have ample opportunity to comment on these assessments. At least once a compliance period, we will update the Board on the adaptive management plan. Where necessary and appropriate, we will consult with the local air district, CDPH, and outside experts. We do not believe that tracking specific public health outcomes will provide data that will be useful to the adaptive management plan because many health impacts are not observed until years after exposure occurs and due to the low levels of exposure anticipated it would be difficult to observe a significant association, and extremely challenging to establish causation.

If adverse co-pollutant impacts are identified and can be attributed to the cap-and-trade regulation, we are committed to promptly developing and implementing appropriate responses through a public process, including consideration and approval by the Board as necessary.

The program imposes a limit on the amount of offsets that an individual covered entity can use for compliance. All offsets used for compliance are real reductions, albeit outside the cap. Allowing a limited number of offsets into the program provides cost-containment benefits and ensures that some GHG emissions reductions occur within the sectors covered by the cap-and-trade program. The program includes provisions that would allow a maximum of 201 $MMTCO_2e$ of offsets through the year 2020. This limit will be enforced through a limit on the use of offsets by an individual entity equal to eight percent of its compliance obligation. It is highly unlikely that the eight percent offset usage limit could result in 85 percent of the reductions required under the cap coming from offsets. Combined with the Allowance Price Containment Reserve, the eight percent limit ensures that a majority of reductions from the program come from sources covered by the program at expected allowance prices, while use of the reserve will relax that constraint if prices rise.

F-4. (multiple comments)
Comment: We strongly urge your administration to prioritize policy options that uphold AB 32's requirements to avoid disproportionate impacts to low income communities; and to maximize environmental, economic and public health co-benefits for California. We are concerned that the carbon trading system approved by ARB will not deliver on those requirements. Studies show that cap-and-trade programs can create pollution “hot spots" in low-income communities of color, exacerbating the toxic burden borne by these communities. In Europe, carbon trading systems have also been plagued by

numerous trading scandals. The carbon trading program approved by ARB replicates many of the problems seen in the European model. (FRIENDSOFEARTH3)

Comment: We urge you to take alternative measures to implement California's most important global warming law, AB 32, that prioritize emissions reductions in communities impacted by toxic air contaminants and preserves social and environmental integrity. (FRIENDSOFEARTH3)

Response: The results of the Emissions Assessment indicate that co-pollutant emissions in California would likely decrease as a result of a cap-and-trade program. This would mainly be attributed to an increase in efficiency and a decrease in the combustion of fossil fuels. In addition, as stated in the responses to comments received during the 45-day comment period, numerous studies have evaluated the potential for inequitable co-pollutant impacts from emissions trading programs on impacted communities, and determined that either there were no impacts or that an emissions trading program could lead to co-pollutant benefits in impacted communities.

We disagree that the California cap-and-trade program "replicates many of the problems seen in the European model." We collaborated with international experts and academics to understand the European program, and to design the California program to avoid any of the issues related to over-allocation in the European program.

As stated in other responses, we evaluated the impacts of a cap-and-trade program to other alternatives when developing the Scoping Plan in 2008, the Staff Report for the cap-and-trade regulation, and again in the *Supplement to the AB 32 Scoping Plan Functional Equivalent Document* (Supplement), which was presented at the August 2011 Board meeting. Considering the objectives of AB 32, we determined that a cap-and-trade program was the preferable approach.

The State of California has the most stringent and successful air quality programs in the country. As described in the Emissions Assessment, our program has substantially improved the air quality in California. The cap-and-trade program will complement our existing air quality program and not impede or in any way alter existing requirements for criteria and toxic air pollutants. Moreover, through the Energy Efficiency and Co-benefits Assessment Regulation for Large Stationary Sources, we are currently collecting information on opportunities for further GHG and co-pollutant emission reductions. We are scheduled to receive these data by the end of 2011. We will initiate a process to ensure that large industrial sources subject to the regulation be required to take cost-effective actions identified under those audits. The audit results, due to ARB by the end of 2011, will inform the development of regulatory requirements that we intend to propose to the Board in 2012. We plan to initiate a separate public process in fall 2011 to discuss metrics and actions to implement this commitment.

However, we understand that situations could arise that might increase air pollution. To ensure that the concerns of the commenters are not realized, we have committed to developing an adaptive management program. At least once each compliance period, we would use information collected through the mandatory reporting regulation, the cap-and-trade regulation, and other sources of information to evaluate how individual facilities are complying with the cap-and-trade regulation. The public will have ample opportunity to comment on these assessments. At least once a compliance period we will update the Board on the adaptive management plan. Where necessary, we will consult with CDPH and outside experts. We do not believe that tracking specific public health outcomes will provide data that will be useful to the adaptive management plan because many health impacts are not observed until years after exposure occurs and due to the low levels of exposure anticipated it would be difficult to observe a significant association, and extremely challenging to establish causation.

If adverse co-pollutant impacts are identified and can be attributed to the cap-and-trade regulation, we are committed to promptly developing and implementing appropriate responses through a public process, including consideration and approval by the Board as necessary.

F-5. Comment: The original regulation failed to meet the criteria set out by AB 32 for market-based compliance mechanisms, and the modifications do not cure these defects. AB 32 requires that before the Board can adopt a market-based compliance mechanism, such as cap and trade, it must: 1) consider the potential for direct, indirect and cumulative emission impacts from these mechanisms, including localized impacts in communities that are already adversely affected by air pollution; 2) design any market-based compliance mechanism to prevent any increase in the emissions of toxic air contaminants or criteria air pollutants; and 3) maximize additional environmental and economic benefits for California, as appropriate. The proposed modifications do not remedy the fact that the Regulation threatens communities with more air pollution and fails to take the opportunity to generate green jobs in California and stimulate California's economy. ARB has still not adopted a methodology for identifying disproportionately impacted, low-income communities in California. Without a screening method it is impossible for ARB to evaluate whether this Regulation will have localized impacts in communities already adversely impacted by pollution. It is unacceptable to take a wait and see approach, when determining the impact of Cap and Trade on vulnerable communities. To comply with AB 32, ARB must identify and analyze all environmental justice communities in California before implementing any market-based mechanism, including this Regulation. The modifications do not correct the fact that the Regulation does not prevent localized or disproportionate impacts or reduce emissions. Due to the program's flexibility, ARB cannot predict where emission reductions will occur or if they will occur at all. Entities could easily buy credits and offsets and not reduce any emissions. ARB cannot rely on the Clean Air Act as a backstop to prevent increased co-pollutant impacts when new or modified major stationary sources (that are also facilities subject to the cap and trade regulation) increase hazardous air pollutant or criteria pollutant emissions in a community because section 112 (regulating HAPs) and New Source Review (as codified in Part D of Title I of the Clean Air Act) allow increases in emissions because MACT or BACT (LAER) do not require zero emissions. Rather, the Clean Air Act's MACT and BACT technology based emissions limits allow for increases. Moreover, under New Source Review, a major stationary source purchases offsets to mitigate the pollution not reduced by BACT under an almost identical scheme as cap and trade: the major source buys offsets from another source in the air basin and the local community gets stuck with the increase in criteria pollutant emissions. The California Clean Air Act likewise does not require zero emissions of toxic or criteria pollutant emissions for new or modified stationary sources. (CRPE4)

Comment: ARB's proposal exacerbates environmental injustice. Low income communities of color are concentrated near California refineries and disparately exposed to air pollutants emitted by refineries along with GHG as co-pollutants that are known to increase risks for health problems which are in fact observed at elevated levels in these communities. This disparate impacts and their exacerbation by the increase in GHG combustion products from refineries—perfect combustion resulting in only carbon dioxide and water being absent from the real world in which we must breathe—are well documented and beyond reasonable dispute. CBE details the evidence once again in our 28 July 2011 comments incorporated herein. ARB's own former advisors have done so as well. ARB again proposes allowing continued and even increased refinery emissions. ARB wrongly ignores this injustice. (CBE2)

> **Response:** These comments do not address proposed 15-day changes to the regulation and restate comments made during the initial 45-day comment period. See response to Comments F-1 and F-4 in the 45-day responses (Chapter III).

G. DEFINITIONS

G-1. Comment: In section 95802(a)(273), the definition of "Other biomass CO_2," the term "biomass CO_2 emissions" is used but this term is not defined. The general term "biomass derived fuel" should be used. It is important to specify "combustion" of the biomass-derived fuel, as some types of biomass-derived fuel (e.g. landfill gas), if not combusted, constitute a separate, uncovered category of GHG emissions. Modify section 95802(a)(273) as follows:
(273) "Other biomass-CO_2" means biomass CO_2 emissions from the combustion of biomass-derived fuels that will be required to hold a compliance obligation. (SCPPA7)

> **Response:** The definition for "Other biomass CO_2" has been deleted from the Regulation. Therefore, the comment is no longer applicable. However, we would like to note that section 95852(i) contains the requirement that a compliance obligation must be held for CO_2 emissions from the combustion of biomass-derived fuel.

G-2. Comment: Section 95802(a)(22) references ASTM D910-07a. The current ASTM Standard Specification for Aviation Gasoline is ASTM D910-11. (VALERO2)

> **Response:** The commenter is concerned that the most recent ASTM Standard Specification was not used in the definition of "Aviation gasoline." We agree and modified the definition to be consistent with specifications as stated in the MRR, section 95102(a.)

G-3. Comment: SMUD points out a slight error in the definition of electric distribution utility. Modify section 95802(a)(82) as follows:

> (82) "Electrical Distribution Utility(ies)" means an Investor Owned Utility (IOU) as defined in the Public Utilities Code sections ~~and~~ 216, and 218, or a local publicly owned electric utility (POU) as defined in Public Utilities Code section 224.3, or an Electrical Cooperative as defined in Public Utilities Code section 2776, that provides electricity to retail end users in California. (SMUD3)

G-4. Comment: SMUD points out a typographic error in the definition of voluntary renewable energy. Modify section 95802(a)(280) as follows:

> (280) "Voluntary Renewable Electricity" or 'VRE' means electricity produced or REC~~D~~s associated with a voluntary renewable electricity generator, and which will not be sold or used to meet any other mandatory requirements or voluntary program in California or any other jurisdiction. (SMUD3)

> **Response:** We appreciate the observation of these typographical errors and made the corrections noted by the commenter.

G-5. Comment: We appreciate and support the change to the definition of

"Greenhouse Gas" in section 95802(a)(115). The deletion of "hydrocarbons" from within the definition is appropriate. (WIRA3)

G-6. Comment: CARB's definition of Replacement Electricity, Section 95802(a)(237), provides an important linkage between the variable renewable resource output and the GHG attribute associated with energy imported into California. CARB's definition provides a reasoned compromise between opposing options on the treatment of imported power GHG emissions. The definition provides the market with flexibility in firming and shaping inherently variable renewable deliveries temporally from the host balancing authority, while retaining verifiable delivery from the renewable host balancing authority to California. This is a reasonable compromise that provides market flexibility while maintaining the integrity of emissions tracking and assignment. (SEMPRAGEN)

> **Response:** We appreciate the support. No response is required.

G-7. Comment: The term "consignee" is used in several places in the Regulation including section 95811(e)(3) with regard to Suppliers of LPG and in section 95852(e)(2) with regard to Suppliers of NGLs. The term "consignee", however, is not defined in the Regulation. To avoid confusion and the potential for inadvertent non-compliance, the Regulation must include a clear definition of "consignee" that addresses any and all uses of the term. Moreover, to ensure that a compliance obligation is not imposed multiple times if LGP/NGLs are resold within the State, the Regulation should also clearly state that the compliance obligation is not intended to apply more than once to the GHG emissions associated with any specific volume of LPG/NGLs. (BP2)

> **Response:** We agree and modified the regulation to stipulate that "consignee," as used in the cap-and-trade regulation, refers to the definition of "Consignee" in the MRR.

G-8. Comment: "Deforestation" is defined as "direct human-induced conversion of forested land to non-forested land." Without a specified definition of "forest," which is not provided in section 95802, this definition is incomplete. There are multiple definitions of "forest," both in the U.S. and internationally, usually focusing on thresholds for canopy cover, tree height, and minimum land area. There are, for example, the definition used by the United States under UNFCCC reporting requirements; U.N. Food and Agriculture Organization definitions used in periodic global and country-level inventories; the generalized definition used in the CDM program, which allows countries to select their own thresholds for canopy cover, tree height, and minimum land area; and others. Different definitions will have different implications for the types of deforestation (and afforestation/reforestation and improved forest management) project activities that will be included or excluded from eligibility. It is important for ARB to be explicit in this regard in order to ensure that the chosen "forest" definition does not unintentionally exclude desired activities or conflict with UNFCCC reporting by the United States government. ACR recommends providing an approved definition of "forest." Winrock and ACR would be happy to provide input in selecting or creating a definition. If ARB intends to rely on the "forest" definitions included in the ARB-adopted forestry and REDD protocols, this could be mentioned in the “deforestation” definition. (MARTINN3)

> **Response:** This comment is outside the scope of the 15-day changes to the regulation, and therefore does not require response. However, we would like to refer the commenter to the ARB Compliance Offset Protocol for Forest Projects, page 74, where “Forestland” is found in the Glossary of Terms, as this information may be helpful. The definition follows below.
>
> > *Forestland: Land that supports, or can support, at least 10 percent tree canopy cover and that allows for management of one or more forest resources, including timber, fish and wildlife, biodiversity, water quality, recreation, aesthetics and other public benefits.*

G-9. (multiple comments)
Comment: In many cases, the proposed modifications to the MRR and the Cap and Trade Rule define relationships in the industry of imported electricity according to the terms of a “written contract” (see sections 95102(a)(354),95102(a)(295), and 98502(a)(258). This is simply not consistent with the realities of the industry, which is fast-paced and highly dynamic, and thus would impose an inefficient and burdensome contract structure. For example, it is standard practice within the Western Systems Power Pool (WSPP) that all transactions with a delivery term of less than one week are verbally confirmed and do not require a written contract. Written contracts for such short-term transactions would be highly inefficient and costly to electricity purchasers. Powerex requests that ARB replace the terms “written contract” and “power contract” with the term “contract” throughout the MRR and Cap and Trade Rules, and that ARB define the term to include both written and verbal agreements. If it is ARB’s intent to disallow the use of non-written contracts under either the MRR or the Cap and Trade Rule, Powerex requests that ARB clearly define the term “contract” so that it is clear to regulated entities how they must structure agreements to meet the rules’ requirements. For example, Powerex suggests that ARB revise the MRR to allow regulated entities to enter into verbal contracts that are backed by written enabling agreements not specific to the particular transaction, subject to the verbal contract. (POWEREX)

Comment: The definition of “Specified Source” in section 95802(a)(258) requires a “written contract” in the absence of ownership to claim a facility as a specified source of electricity: “The electricity importer must have either full or partial ownership in the facility/unit or a written contract to procure electricity generated by that facility/unit.” However, in power trading, a binding sale and purchase agreement may be made orally with only a taped or recorded memorialization, for example by software such as Instant Messenger. ARB should develop a definition of “contract” so that covered entities can have certainty that their agreements for electricity from specified sources will be accepted by ARB. (SCPPA6)

> **Response:** It is not our intent to disallow the use of verbal contracts. We believe the accepted industry practice for the ability to make a binding sale based

on an oral agreement is typically first spelled out in an overall written agreement, with allowance for sub-agreements, which includes how those sub-agreements can be communicated and executed. These sub-agreements could include acceptable types of communication such as verbal communications, phone messages or emails. If this is not the case, and no overall written contract exists, then there is insufficient documentation for ARB to verify and accept the power transactions entered into via verbal or other communication.

G-10. (multiple comments)
Comment: The definition of power contract should match the definition in the MRR and should be used throughout the cap-and-trade regulation in the definition (258) specified sources. Add section 95802(a)(xxx) as follows:

> <u>(xxx) “Power contract” means a written document arranging for the procurement of electricity. Power contracts may be, but are not limited to, power purchase agreements, enabling agreements, and tariff provisions.</u> (SEMPRA3)

Comment: Section 95852(b)(3)(A) requires that that the first deliverers of the replacement electricity have a contract or ownership with the supplier of the replacement electricity. ARB should clarify the definition of the term “contract” and it should be consistent with industry standard usage of the term. That is, a contract for power specifies a delivery location, delivery time, delivery quantity, price and term. (PGE4)

> **Response:** The requirements for verification for determination of a valid contract are contained in the requirements for the MRR. Verification of a valid claim to electricity from a specified source requires (1) evidence of direct delivery defined pursuant to the MRR, section 95102(a), and (2) the reporting entity to meet the definition of a generation providing entity (GPE) pursuant to the MRR, section 95102(a), or have a written power contract, also defined pursuant to the MRR, section 95102(a). A valid claim may be corroborated during verification with additional information such as the location of the first POR relative to the specified facility, settlement data, invoices, matching e-Tags with metered generation when available, and other records allowed pursuant to the power contract, such as email and voice recordings.

G-11. Comment: The term “contract rights” should be clearly defined in the regulation. One criterion for claims of specified imports is that “the first deliverer must be the facility operator or have ownership or contract rights to electricity generated by the facility or unit claimed.” The term “contract rights” is vague and provides no certainty regarding the type of commercial arrangements would qualify. Without further definition as to the type of arrangements that would qualify, the eligibility of contracts for a facility-specific emission rate would be subject to interpretation by verifiers. This is not acceptable. (WPTF2)

Response: The term “contract rights” was used in reference to RPS, and the regulation was modified to clarify that we are referring to definitions in the MRR. During the mandatory reporting process, ARB staff is available to assist covered entities and verifiers with their questions.

G-12. Comment: ARB should modify the Cap and Trade Regulation and MRR to provide a new reporting category and corresponding definition appropriate to Metropolitan’s role and use of imported electricity. Add the definition of “Importer/Non-Marketer to section 95802(a) as follows:

Importer/Non-Marketer or Importer/NM means a utility or entity, such as a public water agency, that purchases electricity generated outside the state of California solely to serve its own load. An Importer/NM does not market this electricity for purposes of resale and does not serve electric retail customers or electric end users. Importers/NM will report under the provisions of MRR, but will not have a compliance obligation under the Cap and Trade Regulation. (MWDSC3)

Response: We did not make this change. It is our intent to attach a compliance obligation, and therefore a price signal, to products and processes that consume electricity in the State.

G-13. Comment: The Regulation includes a provision whereby ARB would look to the Offset Project Operator, Authorized Project Designee, and/or original holder of the Early Action offsets to replace any invalidated offsets if the forest owner or end-user is no longer "in business" (sections 95985(f) and 95990(1)). Please define "in business" and clarify what circumstances would trigger this action. (CE2CC)

Response: We agree and clarified in the regulation where the term “in business” was used, that it was “pursuant to section 95101(h)(2) of MRR.” New section 95985(h) details more clearly the circumstances that the commenter is concerned about.

G-14. Comment: There is no definition of “virgin oils” included in the definitions section. This makes it unclear what oils would qualify under section 95852.2(a)(5). Include a definition of "virgin oils" with an explanation for the rationale for excluding oils that are not "virgin." (CCGG2)

Response: We agree that there is no definition of “virgin oil” in the regulation, as staff believes that this term is self-explanatory in the context in which it occurs in 95852.2(5). In this context, virgin oil is “new,” non-recycled, and not previously processed oil “solely from virgin oils, including esters derived from virgin vegetable oils from corn, soybeans, sunflower seeds, cottonseeds, canola, cramble, rapeseeds, safflowers, flaxseeds, rice bran, mustard seeds, and camelina, and from animal fats.”

Additionally, the commenter is mistaken that oils that are “not ‘virgin’” are excluded, presumably from the covered entity’s compliance obligation as provided by section 95852.2. Section 95852.2(5)(b) clearly includes combustion emissions from two non-virgin oils; tallow and waste oils, as biofuel which are excluded from the covered entities’ compliance obligation.

G-15. Comment: How does CARB define the “transactional relationship” referenced in Appendix A? (DWR2)

Response: “Transactional relationship” is used in context with the discussion of allowance allocation to electricity entities. It means a direct selling and billing relationship between an entity selling electricity (typically a utility) and a retail end-user of electricity. Water utilities typically do not sell electricity to retail end-users and would not be eligible for allowance distribution under the criteria presented in the *Staff Proposal for Allocating Allowances to the Electric Sector*.

G-16. (multiple comments)
Comment: The definition of “Carbon Dioxide Supplier,” in section 95802(a)(45) should be clarified. Praxair was concerned that all entities involved in the industrial CO_2 gas supply chain would be subject to a Cap and Trade compliance obligation. Praxair appreciates staff’s informal clarification that regulating all entities in the supply chain was not CARB's intent. Praxair requests CARB modify Section 95802(a)(45) to remove entities that are not engaged in producing CO_2 from procuring emissions allowances, and reporting under the MRR (see Praxair's comments on the July 25,2011 version of the MRR). This clarification will also achieve greater consistency with the U.S. EPA reporting regulations and avoid concerns that multiple entities in the same supply chain would be regulated for the same activity. Modify section 95802(a)(45) as follows:

(d) This source category is focused on upstream supply. It does not cover:
(1) Storage of CO2 above ground or in geologic formations.
(2) Use of CO2 in enhanced oil and gas recovery.
(3) Transportation or distribution of CO2, unless such transport or distribution involves the import or export of bulk CO2.
(4) Purification, compression, or processing of CO2.
(5) Capture of CO2 rom a production process unit at an upstream facility under separate ownership and control:
(6) On-site use of CO2 captured on site. (PRAXAIR2)

Comment: The definition of “CO_2 supplier” should be clarified to be consistent with federal regulations and focus on upstream supply, so that downstream processors are not subject to redundant requirements in the same CO_2 supply chain. The industrial gas sector operates CO_2 plants that obtain certain refinery gas streams rich in CO_2 and purifies them into carbon dioxide from those streams for use which can be used in many products and processes like refrigeration, dry ice and carbonation. These plants typically do not produce the CO_2 that they process. If the industrial gases sector did not take and purify the refinery gas streams, they would be emitted at the refinery as a waste gas. ARB has consistently held that CO_2 generators should bear the reporting and compliance obligations for CO_2 that they produce. It has not been ARB's intent, and it would not be efficient or equitable, to subject redundant entities in the supply chain to redundant obligations with respect to the same CO_2. Therefore, ARB should ensure that the proposed rules do not impose compliance obligations for distribution-related activities that are unrelated to the production of CO_2 within the state. It is apparent that ARB intended to track the language of the federal definition. However, by omitting the clarifying language in section 95802(b), ARB's draft may unintentionally create ambiguity. ARB should include the following clarifying language, based on 40 C.F.R. section 98.420(b), in the definition of "CO_2 supplier" in both the Cap and Trade Rule and the MRR. This clarifying language should be included in the definitions and relevant sections of the Proposed 15 Day Modifications on Subchapter 10, Article 5, sections 95800-96022, Title 17, PageA-114 (A-10 and A-50) and the Proposed 15 Day Modifications on Subchapter 10 of the "Proposed Amendments to the Regulations for the Mandatory Reporting of Greenhouse Gas Emissions" (sections 95101 page 4, definitions page 16). Modify sections 95802(a)(245) and 95102(a)(59) as follows:

(A) A person or facility is not a Carbon Dioxide Supplier by virtue of performing any of the following activities:

(1) Storage of CO2 aboveground or in geologic formations;(2) Use of CO2 in enhanced oil and gas recovery;
(3) Transportation or distribution of CO2, unless such transport or distribution involves the import or export of bulk CO2;
(4) Purification, compression, or processing of CO2;
(5) Capture of CO2 from a production process unit at an upstream facility under separate ownership and control; and
(6) On-site use of CO2 captured on site. (IGPACC)

Response: We modified section 95802 to more closely align with the federal GHG reporting regulation's definition of a carbon dioxide supplier. In addition, this section was modified to clarify that the source category is focused on upstream supply, and that it does not include the listed activities and uses. Carbon dioxide used in carbon capture and geologic sequestration (CCGS) and carbon dioxide-enhanced oil recovery (CO_2-EOR) is excluded from the cap-and-trade regulation in a different way from how the federal GHG reporting regulation excludes it. Whereas the federal reporting regulation contains separate reporting categories for carbon dioxide suppliers, CCGS, and CO_2-EOR, ARB does not yet include these reporting categories within our MRR, though we signal in section 95852(g) that these activities and uses will be excluded from a compliance obligation through a to-be-developed quantification methodology.

G-17. Comment: The definition of "Permanent" requires that GHG reductions or removal enhancements are either not reversible, or that mechanisms are in place to replace any reversed GHG emission reductions or removal enhancements. ACR strongly agrees with this, and it is consistent with our own permanence requirements. However the definition goes on to require "that all credited reductions endure for a

period that is comparable to the atmospheric lifetime of an anthropogenic CO_2 emission." This definition is unclear, since no atmospheric lifetime is specified. No consensus exists, based on actual measured data, on the atmospheric lifetime of CO_2, but this is generally estimated at several hundred years. Since the estimated atmospheric lifetime of an anthropogenic CO_2 emission is far longer than any minimum offset project term currently being considered, we recommend that ARB delete that portion of the definition and focus on the issue important to the environmental integrity of ARB's Cap and Trade program, i.e. that GHG reductions or removal enhancements are either not reversible, or that mechanisms are in place to replace any reversed GHG emission reductions or removal enhancements. Modify section 95802(a)(186) as follows:
(186) "Permanent" means, in the context of offset credits, either that GHG reductions or GHG removal enhancements are not reversible, or when GHG reductions or GHG removal enhancements may be reversible, that mechanisms are in place to replace any reversed GHG emission reductions or GHG removal enhancements ~~to ensure that all credited reductions endure for a period that is comparable to the atmospheric lifetime of an anthropogenic CO2 emission~~. (MARTINN3)

> **Response:** To address the issues raised by the commenter, the definition of "permanent" was modified to read: "Permanent" means, in the context of offset credits, either that GHG reductions ~~or~~ and GHG removal enhancements are not reversible, or when GHG reductions ~~or~~ and GHG removal enhancements may be reversible, that mechanisms are in place to replace any reversed GHG emission reductions ~~or~~ and GHG removal enhancements to ensure that all credited reductions endure for ~~a period that is comparable to the atmospheric lifetime of an anthropogenic CO_2 emission~~ at least 100 years.

G-18. Comment: The definition of "Beneficial Holding" in section 95802(a)(27) as "the holding of a compliance instrument in the holding account by one entity in which another entity has an ownership interest" requires some revision. SCE (and other electrical distribution utilities) have signed a number of contracts with generators that require it to make generators "whole" for the GHG obligation that they incur when the utility dispatches their facilities in order to serve load. In other words, SCE has a contractual obligation to provide this counterparty either with physical allowances or an equivalent financial payment. However, while SCE is contractually responsible via either method for covering a generator's GHG obligation, there is no language in SCE's contracts with these generators that designate "ownership interest" of any of SCE's compliance instruments. The lack of ownership designation is significant because SCE's pro forma and existing contract language provides SCE the option of compensating generators for their GHG obligation (incurred as a result of dispatch) through financial settlement rather than compliance instruments. Tying "ownership" of a compliance instrument to a specific generator in a beneficial holding relationship would remove any flexibility that SCE would have to financially settle the GHG obligation. This flexibility is significant for allowing SCE to satisfy its contractual obligations at least cost, contributing to an efficient GHG market, and ensuring that electricity customers' rates are minimized. Without such flexibility, SCE's participation in any beneficial holding relationships would be severely restricted, limiting SCE’s ability to effectively manage its GHG contractual obligations at least cost, and potentially raising the cost of compliance for SCE and other parties. ARB should remove the concept of “ownership” of compliance instruments by a principal, and replace it with a “Beneficial Holding Account” for each registered agent. The allowances placed in the Beneficial Holding Account could, at any point, be transferred to a party with whom the agent has a “Long-Term Contract.” In order to ensure that these allowances are indeed used only to meet contractual GHG obligations, allowances could not be removed from this account for any other use. (SCE3)

> **Response:** We modified the definition of “Beneficial Holding” to mean the acquisition and holding of compliance instruments by a registered entity to be transferred to another registered entity under an agreement disclosed to ARB.

G-19. Comment: "Air Dried Ton of Paper" is defined as paper with 6 percent moisture content. The industry definition for Air Dried Ton is 10 percent moisture content. Temple-Inland believes that the proposed definition should be changed to reflect the industry standard and avoid potential inconsistencies with other reported production data generated by industry. Alternatively, a standard could be written based on "bone dry" or "oven dry" tons, both defined as 0 percent moisture content. Under either scenario, conversions will have to be made from the measured production rate which is termed scaled tons and defined as "machine dry" tons. The term "machine dry" is variable from mill to mill, grade to grade and even from time to time. (TI)

> **Response:** Since five paper and paper mills covered under the program produce products with different moisture content, we needed a common unit. We defined air-dried ton as product with 6 percent moisture content, to be consistent with European Union Emissions Training System. Staff believes that it is appropriate as far as we are applying common unit for all types of paper products covered by the program.

G-20. (multiple comments)
Comment: The use of the word “rent” in the definition of “Tolling Agreements” in section 95801(267) could create accounting impacts. Under Generally Accepted Accounting Principles (GAAP) accounting rules, a tolling agreement may or may not be a "lease." Use of the word "rent" implies that a tolling agreement is a lease, which might contradict the accounting rules. PacifiCorp recommends using a different word consistent with the concept of an energy conversion service. (PACIFICOR3)

Comment: The Regulation includes a definition for tolling agreement, but it is not a term that is found in the Regulation. LADWP recommends that this definition be deleted. Modify section 95802(a)(267) as follows:

> ~~(267) “Tolling Agreement” means an agreement whereby a party rents a power plant from the owner. The rent is generally in the form of a fixed monthly~~

~~payment plus a charge for every MW generated, generally referred to as a variable payment.~~ (LADWP4)

Response: We agree with the second commenter and deleted "Tolling Agreement" from the list of definitions in the regulation. Since it was deleted, the first comment is no longer applicable.

G-21. Comment: The definition of Renewable Energy Certificate "REC" should be changed. PacifiCorp recommends changing section 95801(239) from "REC means a certificate" to "REC includes a certificate;" a REC represents more than a certificate. A REC is a property right and should be consistent with other definitions used in the Renewable Portfolio Standard provisions. (PACIFICOR3)

Response: We are consistent with the renewable portfolio standards provisions and are using the definition derived from the California Energy Commission's Renewable Energy Program Overall Program Guidebook, Third Edition. *Renewable Energy Certificate (REC)* — as defined in Public Utilities Code Section 399.12, Subdivision (f)(1) to mean a certificate of proof, issued through the accounting system established by the Energy Commission pursuant to Section 399.13, that one unit of electricity was generated and delivered by an eligible renewable energy resource. As specified in Section 399.12, Subdivision (f)(2), a REC includes all renewable and environmental attributes associated with the production of electricity from an eligible renewable energy resource, except for an emissions reduction credit issued pursuant to Section 40709 of the Health and Safety Code and any credits or payments associated with the reduction of solid waste and treatment benefits created by the utilization of biomass or biogas fuels. As specified in Section 399.12, subdivision (f)(3), no electricity generated by an eligible renewable energy resource attributable to the use of nonrenewable fuels, beyond a de minimus quantity, as determined by the Energy Commission, shall result in the creation of a renewable energy credit. (see http://www.energy.ca.gov/2010publications/CEC-300-2010-008/CEC-300-2010-008-CMF.PDF)

G-22. Comment: Section 95802(a)(145) defines "Limited Use Holding Account" as meaning "an account in which allowances are placed after an entity qualifies for a direct allocation under section 95890(b)." However, section 95892(b)(2) permits Publicly Owned Utilities (POU) to direct the Executive Officer to place all or a portion of their directly allocated allowances in the POU's compliance account instead of its limited use holding account. Thus, the definition of "limited use holding account" should be revised. Modify section 95802(a)(145) as follows:

(145) "Limited Use Holding Account" means an account in which allowances are placed after an entity qualifies for a direct allocation under section 95890(b) unless the entity elects to have its directly allocated allowances deposited into its compliance account pursuant to section 95892(b)(2). Allowances placed in this account can only be removed for consignment to the auction pursuant to section 95831(a)(3). (SCPPA6)

Response: The definition of "limited use holding account" does not exclude allowances from being distributed directly into other accounts. It defines a type of account in which:

(A) The entity may not transfer compliance instruments from other accounts into the limited use holding account; and

(B) The entity may not transfer compliance instruments from the limited use holding account to any account other than the Auction Holding Account.

G-23. Comment: With the incorporation of the definition for "facility" into the revised MRR regulation, the proposed Cap and Trade Regulation now contains multiple and confusing references to the term "facility" as it applies to oil and gas production operations:

- The proposed Cap and Trade Regulation, section 95812(c)(4) states "The applicability threshold of oil and gas producers will be determined at the operating entity listed on the state well drilling permit or operating permit in accordance with section 95151(a)(1) of MRR. The applicability threshold for oil and gas producers is 25,000 metric tons or more of CO_2e per data year."

- In the amended MRR regulation, section 95151(a) refers to section 95150 for source categories and section 95101 for applicability. Section 95150 refers to federal regulations at 40CFR98.230(a)(1)-(a)(8). The citation at 40CFR98.238 defines onshore petroleum and natural gas production facility as "all equipment... in a single hydrocarbon basin."

- Finally, the proposed Cap and Trade Regulation section 95802(a)(95) defines "Facility" as "any physical property, plant, building, structure, source, or stationary equipment located on one or more contiguous or adjacent properties in actual physical contact or separated solely by a public roadway or other public right-of-way and under common ownership or common control, that emits or may emit any greenhouse gas."

WSPA believes that the proposed Regulation should provide clear language stating that the "single hydrocarbon basin" definition from the MRR is to be used only for establishing GHG reporting requirements, which is consistent with federal regulations. However, compliance obligations under the Cap and Trade Regulation should be limited to "facilities" that exceed the 25,000 tpy threshold, where "facility" is defined as contiguous or adjacent properties under common control as defined under section 95802(a)(95). WSPA recommends that the proposed regulations reflect that the scope of the Cap and Trade compliance obligation for oil and gas production apply only to facilities, as defined in section 95802(a)(95) for contiguous or adjacent properties that exceed the 25,000 ton threshold. (WSPA3)

Response: We did not make those changes. In section 95852, *Emission Categories Used to Calculate Compliance Obligations*, subsection (h) states that

> "Operators of the facilities specified in section 95101(e)(2)-(5) of MRR have a compliance obligation for every metric ton of CO_2e from the source types specified in section 95152(c)-(f) of MRR, except as specified in section 95852.2 of this article, that is contained in an emissions data report that has received a positive or qualified positive emissions data report, or for which emissions have been assigned." This subsection requires that the compliance obligation is based on the facility, as defined in the MRR, section 95101(e)(2)-(5). This treatment for the oil and gas production sector is also consistent with the U.S. EPA regulation.

G-24. Comment: The Modifications include a new definition of "Primary Refinery Product." This definition is key to the amount of allocations provided to an individual facility because it is embedded within the calculation details when determining free allocation amounts. WIRA urges that Residual Fuel Oil ought to be included in the definition of a Primary Refinery Product. Quoting from Appendix J-Allowance Allocation (p. J-41), dated October 28, 2010, "The simplest product output metric that can be conceived for the refining sector is the total product produced from each facility. Under such a "simple barrel" approach each refiner would report annual production of total barrels of major petroleum products such as gasoline, diesel, jet fuel and residual fuel oil to ARB." The inclusion of Residual Fuel Oil into the definition of Primary Refinery Product would be consistent with this original intent of the program. Additionally, its inclusion would not perceivably impact the program in aggregate due to the fact that only a very small quantity of Residual Fuel Oil is produced in California as a finished refinery product. The relative size of the allowances associated with Residual Fuel Oil production is on the order of 0.08 percent of the statewide cap. But even though it is small in the aggregate, to one WIRA member, Residual Fuel Oil is a substantial percentage of their finished product percentage and not including it would have Clerk of the Board significant negative consequences to their allowance level. By its very nature, Residual Fuel Oil is a "primary" refinery product being derived from the most elementary of refining processes: distillation. Container ships and other large oceangoing vessels use Residual Fuel Oil as their transportation fuel. No valid distinction can be made between Residual Fuel Oil and gasoline and diesel. All are transportation fuels. While many larger, more complex refiners have opted to install additional equipment for further processing Residual Fuel Oil into other petroleum products, doing so is just an option. This option to further process Residual Fuel Oil is not one that all refineries have exercised or can even consider, given the economically prohibitive costs and capital expenditures involved with adding necessary refining units. Specifically, WIRA's affected member has chosen a business model that sells this product directly into the market rather than to perform additional, energy- and emissions-intense processing techniques. Quoting from Appendix J-Allowance Allocation (p. J-21), dated October 28, 2010, "Basing free allocation to industrial covered entities on product benchmarks... provides entities the correct incentives to produce a given product in the cleanest (lowest GHG-emitting) way possible." To omit Residual Fuel Oil from the definition of Primary Refinery Products is in contradiction to this statement and, in fact, penalizes such a refiner for not having additional greenhouse gas emitting processes. In setting up this program CARB consistently pushed in the direction of a lower carbon economy without overtly picking winners and losers, but the exclusion of Residual Fuel Oil could easily be classified as such a decision. Therefore, WIRA strenuously urges that Residual Fuel Oil be included in the definition of Primary Refinery Product. (WIRA3)

> **Response:** We are not proposing any additions or deletions to the product types included in the "simple barrel" metric at this time. Beginning with the 2011 data year, ARB will collect detailed, third-party verified, refinery product data as part of the effort to monitor for emissions leakage in this sector. This data set would allow for future changes to product types in the metric as needed.

G-25. (multiple comments)
Comment: "Variable Renewable Resources" are defined as "run-of-river hydroelectric, solar, or wind energy that requires firming and shaping to meet load requirements" in section 95802(a)(272). This definition is flawed in that it states that such energy "requires firming and shaping to meet load requirements." Run-of-river hydroelectric, solar or wind energy may be firmed and shaped, but do not have to be. These eligible renewable resources can be dynamically scheduled into a California balancing authority area, or they can be scheduled in real time using firm transmission. SB x12 recognizes this by assigning energy so delivered to the first portfolio content category. In any case, firming and shaping are not necessary to meet load requirements. BP suggests that the definition of Variable Energy Resource be revised to state: "Variable energy resources means run-of-river hydroelectric, solar, or wind energy that may be firmed and shaped." (BP2)

Comment: The definition of "Variable Renewable Resources" should be deleted. The term appears in only two sections of the Regulation: section 95802(a)(237) defining "Replacement Electricity" and section 95852(b) regarding the calculation of the compliance obligation for replacement electricity. SCPPA recommends removing the word "variable." If ARB adopts SCPPA's recommendation, the term variable renewable resources will not appear anywhere in the Regulation. Accordingly, the definition of "Variable Renewable Resources" in section 95802(a)(272) would be surplus and should be deleted. (SCPPA6)

> **Response:** The term "variable renewable resources" was used in two places in the regulation that have been struck out, and there were not any references to the term "variable energy resources" in the regulation. Because of this, the comments are no longer applicable.

G-26. (multiple comments)
Comment: SMUD sees no need for the term "up to" to be included in the definition of compliance instrument, as there seems to be no case where a compliance instrument represents less than one metric ton of CO_2e. Modify section 95802(a)(52) as follows: (52) "Compliance Instrument" means an allowance, ARB offset credit or sector-based offset credit. Each compliance instrument can be used to fulfill a compliance obligation equivalent to ~~up to~~ one metric ton of CO_2e. (SMUD3)

Comment: Section 95922. Banking, Expiration, And Voluntary Retirement. “External GHG ETS” is a defined term in section 95802(94). Thus, this is a conforming change.

> (c)(3) ~~t~~<u>T</u>he instrument is retired by an approved external GHG ~~emissions trading system~~ <u>ETS</u>… (MID3)
>
> **Response:** No changes were made to the regulation based on the comments. These changes are not necessary to add any clarity to the intent of the regulation.

G-27. Comment: The definition for "operational control" should be expanded to include a counter party in a long-term PPA that has exclusive rights to 100 percent of the net electrical output from the facility. Certain performance provisions require Goal Line to operate a minimum number of hours per month in order to provide the needed power capacity (and earn essential, agreed capacity revenues) and to not be in breach of the PPA. By virtue of the PPA as authorized by CPUC, the buyer, SDG&E in this case, has operational control of the facility and should be the entity with the compliance responsibility under CARB's Cap and Trade program. Modify section 95802(a)(179) as follows:

> (179) "Operational control" for a facility subject to this article means the authority to introduce and implement operating, environmental, health, and safety policies. In any circumstance where this authority is shared among multiple entities, the entity holding the permit to operate from the local air pollution control district or air quality management district is considered to have operational control for purposes of this article <u>or, in the case of a facility with a long-term Power Purchase Agreement where the facility is precluded from selling any energy to any entity other than the counterparty, then the counterparty has operational control</u>. (GOALLINE)
>
> **Response:** No changes were made to the regulation based on the comments. The suggested edits are to address long-term contracts, and we have chosen to encourage the contracted parties to renegotiate the terms of the contracts.

G-28. Comment: Amend the current definition for “conversion technology,” which is technically inaccurate and practically infeasible to comply with. First, the current definition states “the technology does not use air or oxygen in the conversion process, except ambient air to maintain temperature control.” Existing gasification technologies known by the Bureau utilize limited supply of oxygen for the gasification of organic material to produce synthetic gas (syngas). Syngas is comprised of hydrogen and carbon monoxide and can be used to generate electricity or produce transportation fuels. Second, it also states that "the technology produces no discharges of air contaminants or emissions, including greenhouse gases." All conversion technologies, including biological and thermal technologies, produce air emissions during the biofuel generation process or when the syngas/biogas is used for electricity production.

Consequently, all "conversion technologies" produce air emissions and must instead be required to be equipped with the Best Available Control Technology to mitigate emissions, and to meet or exceed all applicable requirements set by the local, state, and federal agencies. (CLABS)

> **Response:** We agree with the commenter and removed the requirements in *95852.2., Emissions without a Compliance Obligation*, that conversion to a clean-burning fuel of municipal solid waste required that the technology does not use air or oxygen, and that the technology produce no air contaminants or emissions.

G-29. Comment: The definition of "Distillate Fuel No. 1" does not include jet fuel. However, because Distillate Fuel Oil No. 1 is defined with reference to the maximum distillation temperature (and the potential for jet fuel to fall into the range noted), we think it would be a helpful clarification to note that this definition excludes jet fuel. We saw such clarification was included for kerosene and we are seeking a similar edit. Modify section 95802(a)(71) as follows:

> (71) "Distillate Fuel No. 1" has a maximum distillation temperature of 550 F at the 90 percent recovery point and a minimum flash point of 100 F and includes fuels commonly known as Diesel Fuel No. 1 and Fuel Oil No. 1, but excludes kerosene <u>and kerosene-type jet fuel</u>. This fuel is further subdivided into categories of sulfur content: High Sulfur (greater than 500 ppm), Low Sulfur (less than or equal to 500 ppm and greater than 15 ppm), and Ultra Low Sulfur (less than or equal to 15 ppm). (UNITEDAIRLINES2)
>
> **Response:** We agree with the commenter and added the following definition for kerosene type jet fuel:
>
> "Kerosene-Type Jet Fuel" means a kerosene-based product used in commercial and military turbojet and turboprop aircraft. The product has a maximum distillation temperature of 400 °F at the 10 percent recovery point and a final maximum boiling point of 572 °F. Included are Jet A, Jet A–1, JP–5, and JP–8.
>
> Additionally, since kerosene-type jet fuel is defined as a "kerosene-based product", it is effectively excluded from the definition of "distillate fuel #1."

G-30. Comment: The terms "located at a well pad" and "associated with a well pad" or "associated with wells" used in the definition of an "onshore petroleum and natural gas production facility" and in other places in the regulation are not clearly defined in either 40 CFR Part 98 Subpart W or in ARB's MRR rule. As a result, operators of onshore oil and gas production facilities are each making their own interpretations of how to define their facilities to report 2011 emissions. There will likely be different interpretations by different operators, resulting in inconsistencies. If this new reporting requirement brings new facilities into the cap-and-trade universe or significantly increases reported emissions from facilities already in the universe, how will that affect the initial allocation process and those facilities' ability to comply with the requirements of the cap-and-trade rule? (STEUBE)

> **Response:** The definition of which oil and gas production facilities are covered has been clarified in the MRR rule. We do not believe that capturing additional sources would significantly change the benchmarks set for this sector.

G-31. Comment: In section 95831(a)(5)(B), ARB uses the phrase “clearing entity.” PG&E requests that ARB make conforming changes to the definition of clearing entity in section 95802 to avoid potential confusion due to the multiple connotations of the term in the commodity trading industry. (PGE4)

> **Response:** We did not define the term “clearing entity” at this time. We believe that the requirements and responsibilities associated with these entities in the regulation provide sufficient clarity as to how the term is used.

H. ECONOMIC IMPACTS

H-1. Comment: PEB has a long term steam sales agreement with UC-B that expires in August 2017. The Regulations as currently proposed, effectively impose an unrecoverable cost upon PEB not contemplated by the authorizing legislation, because its steam sales contract does not explicitly contemplate recovery of the charges for GHG emissions arising from cogenerated steam and there is currently no other GHG cost recovery mechanism available to PEB. The intent of GHG programs generally is to transfer the cost of GHG generation to the end users/consumers who, in turn, will modify their behavior in such a manner as to cause a reduction in the generation of greenhouse gasses. That intention is entirely frustrated in the case of PEB, as these costs are stranded at PEB and no mechanism is available to PEB with which it might pass these costs on to the ultimate end user of the steam. If there is no recovery by PEB from UC-B, or otherwise, under the GHG program Regulations, then the intent of the GHG program is frustrated. PEB clearly becomes a stranded asset, bearing an unrecoverable economic cost, while UC-B, the actual consumer, is essentially provided an exemption from the cost of the GHG program in the absence of any effective incentive to modify its energy consumption behavior or reduce its carbon footprint. In fact, UC-B's thermal needs may increase over the next five years, thus locking PEB into an even greater steam load obligation and greater GHG losses—effectively a "downward spiral" for the project resulting directly from the cost of the proposed GHG Regulations. The PEB facility was developed in reliance upon California State and US Federal energy policies designed to encourage the development, financing, ownership and operation of energy efficient cogeneration facilities. Similar California policies created a variety of incentives for PG&E to purchase the generated electricity and for UC-B to purchase a reliable, cost effective and environmentally beneficial central source of steam. The proposed Cap and Trade Regulations, as contemplated by CARB, would undermine these policies and would effectively cause PEB to become an economically stranded asset whose contractual framework has been frustrated by an unreasonable regulatory cost that would be inequitable and whose disparate economic impact would cause unique harm to PEB. The financial impact of the GHG Regulations, as proposed (absent an end-user pass through), is of such material economic significance as to pose a potential threat to the mechanical reliability and continued predictable operation of this cogeneration facility. Further, these Regulations threaten PEB's underlying economic viability, posing a level of financial risk and uncertainty to lenders and equity investors not contemplated by PEB, or similarly situated projects, when originally structured and financed. An equitable solution, recognizing the serious problems facing PEB under the proposed GHG Regulations, will send a strong positive message to those parties contemplating new investments in the next generation of cogeneration facilities in California, to the effect that CARB recognizes the unique value and contribution of cogeneration technology in the reduction of greenhouse gasses, and will also signal CARB's affirmative support for such new investments. CARB should recognize PEB's situation and provide the needed case-by-case relief because the current "universal solution" does not apply to PEB's unique situation. This is clearly a transition issue and needs to be dealt with as such. Beyond 2017, any new contractual agreements for electricity or steam will include a mechanism for GHG recovery. PEB believes that

CARB should allocate free allowances, an exemption from the Regulations until 2017 or other comparable relief to PEB so that it is no longer a stranded asset and is held harmless from the current adverse impact of the proposed Regulations. (PEBI)

Response: Generators of electricity are not eligible for free allocation of emissions allowances because we believe that the cost of allowances can be passed on to the consumers of the electricity. Free allocation of emissions allowances is only for sectors at risk for emission leakage.

We realize that some electricity generators may have existing contracts that prevent them from fully passing through the carbon costs associated with the cap-and-trade program. We have closely examined this issue, but do not believe it is our role to renegotiate contracts for parties because of new environmental regulations. We encourage parties to resolve this issue on their own.

In Resolution 11-32, the Board directed the Executive Officer to monitor progress on bilateral negotiations between counterparties with existing contracts that do not have a mechanism for recovery of carbon costs associated with cap-and-trade for industries receiving free allowances pursuant to Section 95891, and to identify and propose a possible solution, if necessary. For fixed-price contracts between independent generators and investor-owned utilities, the Board further directed the Executive Officer to work with the California Public Utilities Commission to encourage resolution between contract counterparties.

H-2. (multiple comments)
Comment: To ensure GHG reductions are achieved while maintaining the competitiveness of California businesses and the health of the economy, it is critical for CARB to monitor key indicators of not only the GHG reductions that are occurring but also indicators of the health of California's economy. We urge CARB to identify and monitor these key indicators, so that any inadvertent problems that may occur can be corrected before significant damage is done to California economy or environment. (CALCHAMBER3)

Comment: This Regulation impacts a significant portion of California's businesses and consumers. It is imperative that the State monitor leading indicators that reflect the economic health of California. California must be positioned to identify any potential problems that may be inadvertently caused by this regulation, before they cause significant damage to the economy so that any regulatory structural problems can be corrected in a timely manner. CCEEB recommends that the ARB include provisions in the Cap and Trade Regulation to:

1. Monitor specific economic indicators, including the following Cap and Trade market elements:
   - o the price in the auctions,
   - o the functioning of secondary markets,
   - o adequacy of the Allowance Price Containment Reserve, detection of market manipulation,

- offset supply,
- evidence of contract shuffling,
- progress towards achieving the 2020 target, total cost of the program,
- jobs in manufacturing, vacancy rates,
- home sales,
- volume of trade through ports, Gross State Product,
- energy prices, and
- other indicators used by the Department of Finance to monitor the health of California's economy;

2. Establish formal reviews of the regulation at least once each compliance period; and
3. Develop and implement a more structured process and approach for evaluating the comparative cost-effectiveness of program measures, as well as the relative cost-effectiveness of those measures vis-a-vis the Cap and Trade program and identify any potential problems. (CCEEB3)

Response: The comments fall outside the scope of the first 15-day changes to the regulation. However, we agree that it is important to monitor the environmental and economic effects of the cap-and-trade program, and we will do so. We are contracting with a market monitoring firm who will review trading activity and establishing a market surveillance committee who will review and comment on the operations of the program. Contract shuffling, in the context of electricity, is specifically prohibited by the regulation.

H-3. Comment: While other regions have reconsidered their GHG policy responses, California has begun to implement policies aimed at achieving AB 32's 2020 GHG targets, with its Cap and Trade system scheduled for implementation in 2012, albeit with a "soft-start." As a result, California will begin its Cap and Trade system without the commensurate participation it had hoped to stimulate from neighboring political subdivisions and the federal government, which in turn will have major consequences likely resulting in a range of negative economic impacts on California businesses. (CIPA)

Response: The comment falls outside the scope of the first 15-day changes to the regulation. Please see responses to the 45-day comment period regarding potential for economic impacts of a California-only cap-and-trade program. However, we are actively working with WCI partners in an effort to establish a larger regional market.

H-4. Comment: CCEEB believes that because it is unlikely that California's program will be broadly linked with other state, federal or international programs in the early years, the combined effects of the cap slope and the allowance reserve deductions in the first and second compliance periods are likely to result in serious impacts to the economy. In the Functional Equivalency Document (FED) for the Cap and Trade, ARB reported 2010 emissions, which are far below projections made to justify the capped reductions. Since there are no linkages and there is a reduced need for emission reductions, CCEEB recommends that the cap slope be revised to reflect a smoother transition of 1 percent in 2013 and 2014, and 2 percent per year in the second compliance period. This creates a smoother transition and realistically addresses the potential that California's Cap and Trade program will operate without the possibility of broad linkage to other state or federal programs in the first 5 years. (CCEEB3)

> **Response**: We disagree that the emissions reduction trajectory should be changed because other partner jurisdictions are not ready to begin in 2012. Other jurisdictions may be ready to join by 2013. Also, the projections used to set the cap considered a decline in emissions in 2010, which are the same emissions used in the FED mentioned by the commenter. Furthermore, with the continued economic slowdown, free allocation of allowances in early years, and estimates of ample offset availability, it should not be problematic or excessively costly for program participants to meet early reduction requirements. Our economic analysis shows that program goals can be met without significant adverse impacts to business or the economy as a whole as a result of the program.

H-5. Comment: The proposed Regulations may have significant negative consequences to the fiber glass insulation industry in California. Because this Regulation would have serious deleterious impacts on the fiber glass insulation manufacturers in the State, it would also have an adverse impact on California’s economy. As noted below, the State of California has stated that increased energy efficiency in buildings has the greatest potential for reducing greenhouse gases. Insulation is the quickest, most economically feasible, and most proven means for achieving those reductions. Fiber glass insulation is the most widely-used insulating material in residential and commercial construction and retrofit applications. If California inhibits the manufacture of this material within the State, it will impair the ability of the State to meet its goal of greenhouse gas reduction and force those needs to be supplied by products made at fiber glass manufacturing facilities located elsewhere in the U.S., Canada, and Mexico. (NAIMA2)

> **Response**: The fiberglass sector will be receiving free allocation of allowances for the purposes of transition assistance and to prevent economic leakage. Further, the manner in which allowances are allocated (i.e., output-based) allows for any increases in production that will accompany the improvements in building efficiency that are expected as part of the cap-and-trade program.

H-6. Comment: We believe significant measures must be taken to minimize regressive economic effects on consumers of natural gas products (small businesses, residents, etc.) when they are included in the rule in the second compliance period. (EDF4)

> **Response**: We agree that methods for reducing the impact to consumers should be implemented when other fuels come under the cap in the second compliance period. In Board Resolution 10-42, the Board agreed that the potential uses of

allowance value that were recommended by the EAAC represent good uses of the allowance value. These included returning allowance value to households either through lump-sum rebates or through cuts or avoided increases in the State's individual income or sales tax rates. If allowance fraction is returned through tax rate cuts, a small fraction of the allowance value should be reserved to finance income transfers to low-income households, to avoid disproportionate economic impacts on such households. Please see Board Resolution 10-42 and the EAAC report for additional information. Furthermore, in Resolution 11-32 the Board directed the Executive Officer to develop recommendations for the appropriate use of auction revenue. The Board further directed that these recommendations should consider the Board's direction in Resolution 10-42.

H-7. Comment: Did CARB consider whether water users' electricity-bill rebates will compensate those users for the increased water rates? If so, what are the factual basis and standards used to make the determination that water users would be adequately compensated? (DWR2)

Response: The utilities have indicated that they will use allowance value for the benefit of their ratepayers. The allocation mechanism to Electrical Distribution Utilities on behalf of ratepayers should compensate all ratepayers for the costs of the program, provided that utilities are meeting their reduction requirements (e.g., 33 percent RPS) that were assumed as part of the cost burden analysis. Additional value is provided to utility ratepayers for early investment in energy efficiency and renewables. We believe this additional value is sufficient to compensate electricity ratepayers for the greenhouse gas costs in the electricity portion of water rates.

Nevertheless, in Resolution 11-32 the Board directed the Executive Officer to continue discussions with stakeholders to identify and propose, as necessary, during the initial implementation of the cap-and-trade program, potential amendments to the regulation regarding the distribution of allowance value associated with cap-and-trade compliance costs from using electricity to supply water, and the expected ability of allowance allocation and other measures to adequately address the incidence of these costs equitably across regions of the State.

I. ELECTRICITY

Allocation

Methodology

I-1. Comment: The University of California (UC) meets CARB's criteria for receiving an allocation of allowance value by having a direct transactional relationship with their end-use customers. Allocating allowance value to the University of California (UC) will further AB 32 goals, while reducing UC's compliance costs; helps ensure fair treatment for self-generators of electricity; and provides recognition for early adopters of CHP plants. Therefore UC proposes the following Cap and Trade compliance path:

- UC campuses that are directly regulated under Cap and Trade be required to submit a five-year plan to CARB that details anticipated investments in GHG abatement.
- Pending CARB's approval of these plans, regulated UC campuses will receive an allocation of allowances sufficient to cover 100 percent of their surrender obligation for the duration of the cap-and-trade program.
- In exchange for this free allocation, CARB will require regulated UC campuses to invest a sum commensurate with the market value of the freely allocated allowances in GHG abatement projects. (UC3)

Response: We freely allocated allowances only to emissions intensive and trade exposed (EITE) industry, for transition assistance and leakage prevention, and to electric distribution utilities, for the benefit of ratepayers. The University of California is neither an EITE nor an electric distribution utility. We did not allocate allowances to CHP facilities that have a direct transactional relationship with their end users. For the price signal from the cap-and-trade program to be effective, the cost of GHG emissions must be passed through to end users. We expect UC to pass through carbon costs to end users. Furthermore, electric distribution utilities are allocated allowances to benefit ratepayers; in part because electric distribution utilities have the obligation to purchase and generate electricity, incurring carbon costs directly or indirectly, and have other mandates to reduce GHGs. For example, unlike UC, electric distribution utilities must meet the 33 percent RPS. The University of California is in the same position as other entities, such as local governments and state agencies; some of whom generate their own power. Because they are neither EITEs nor electric distribution utilities, they do not receive allowances.

Nevertheless, in Resolution 11-32 the Board directed the Executive Officer to coordinate with the State universities and stakeholders to evaluate options for compliance, with amendments to the regulation as appropriate, including options of the use of auction revenue, and report back to the Board in summer of 2012.

I-2. Comment: Electricity generating facilities is not listed in table 8-1, nor in table 9-1, which include industry sectors eligible for direct allocation of GHG allowances. Please clarify whether this sector will have to purchase their total allowances through the auction process. (AP)

Response: Electricity generating facilities will need to purchase allowances through the auctions or on the secondary market.

I-3. Comment: For a POU that is a member of a JPA or that has a contractual relationship with a deliverer of electricity used to serve retail native load, LADWP recommends that a provision be added that allows a POU to transfer allowances directly from its compliance account to the compliance account of the JPA or deliverer of electricity. POUs need flexibility to move allowances to the entity that has the compliance obligation to surrender allowances associated with the emissions related to serving native load. This provision would not result in the transfer of allowances to cover emissions associated with wholesale electricity sales. Modify section 95831(a)(4)(B) as follows:

<u>(B) A Publicly Owned Electric Utility may transfer compliance instruments from its compliance account to the compliance account of a Joint Powers Agency in which the POU is a member to the compliance account of a deliverer of electricity or with which it has a power purchase agreement, pursuant to section 95892(b)(2) for electricity that serves retail load only.</u> (LADWP4)

Response: The language was modified in section 95892(b) to clarify that publicly owned utilities (POUs) and cooperatives may only ask for allocations to be placed into compliance accounts of facilities they (or a Joint Powers Agency with which they have a relationship) operate.

I-4. Comment: PG&E supports ARB's decision to allocate allowances to electric distribution utilities for protection of electricity customers. PG&E supports ARB's recognition of the "customer cost burden" principle, the inclusion of an "early action" element in the allocation methodology and allocation to electric distribution utilities for the protection of customers. First, PG&E believes that the costs of meeting electric sector GHG reduction goals will flow through commodity markets to customers, and, therefore, revenue from allowance auctions should be used to mitigate those increased customer costs. PG&E has consistently advocated for a return of allowance value, via utilities, solely for the benefit of customers. Second, PG&E believes additional "early action" allocation, above the expected cap-and-trade cost burden, recognizes customers' past investments in low-carbon resources and will help mitigate costs associated with AB 32 electric sector programmatic measures. (PGE4)

Response: We agree. Thank you for the comment.

I-5. (multiple comments)
Comment: CCSF supports an allowance allocation mechanism that recognizes and rewards those electric distribution utilities that already have significantly reduced GHG

emissions well before the adoption of AB 32. One example would be an allocation mechanism such as the ARB's "Emissions Efficiency Benchmark" used for other sectors, which allocates allowances based on an average of GHG emissions per unit of output and thus rewards entities that have historically operated with lower GHG emissions. Another example, also considered by the ARB, would transition over time from allocating allowances based on emissions to increasingly allocating allowances based on sales or throughput. This approach balances the rewarding of entities with historically low GHG emissions while providing a transition period for high-GHG entities to adjust their operations. (SFMAYOR3)

Comment: We note for the record our disappointment in ARB's proposed allocation of allowances among the state's electric utilities. ARB identified two broad policy objectives it set out to achieve (and reconcile) in developing an allocation methodology: to reward early action from utilities who invested in demand-side reductions and a relatively clean resource mix; and to offset the cost burden on customers of utilities who underinvested in efficiency and maintained a higher carbon-intensive resource mix. In December 2010, ARB proposed to allocate allowances based on three factors: early action (defined as qualifying renewable energy investments from 2007-2011), cumulative energy efficiency investments (also indicative of early action), and customer cost burden (a product of the emissions-intensity of each utility's resource mix). But the actual proposal reveals the methodology is largely a product of the third factor, as customer cost burden accounts for more than 90 percent of each utility's allowance allocation. We maintain that the allocation methodology should give significantly more weight to the other two factors, which would more effectively reward and encourage the transition to clean energy. We appreciate that the methodology has buy-in from the utilities, and recognize ARB's extensive work and collaboration in developing this approach. As proposed, however, we remain concerned that the allocation scheme disadvantages early movers on clean energy and sends the wrong signal for jurisdictions developing or contemplating the development of a carbon market. (KUSTIN16)

Comment: We are very opposed to the method proposed for allowance allocation to the utility sector. The actual proposal uses "customer cost burden" for more than 90 percent of each utility's allowance allocation. We request the customer cost burden factor should be no more than 10 percent of each utility's allowance allocation. One need for this shift is that LADWP calculates that the ARB allocation results in LADWP having absolutely no cost impact from AB 32 cap and trade, even while burning many, many tons of coal all the way to 2027. Surely, letting LADWP benefit from hanging on to coal is not what the legislature had in mind in passing AB 32. (EDLA)

> **Response:** We understand that other methods of allocation, such as a sales-based approach, would have greater advantage to those utilities that made early investments in less emissions-intensive resource mixes. However, we do not believe that it is necessary to disadvantage electric distribution utilities that have not made similarly aggressive investments, in order to establish the correct marginal incentive to reduce emissions. We believe that our method of allocation

achieves this objective; and further, that establishing the correct marginal incentive is by far the most important signal to send to other jurisdictions considering similar carbon pricing programs.

I-6. Comment: Section 95870(d) increases the allocation to electrical distribution utilities by approximately 10 percent. WSPA believes that the allocation to utilities be proportional based on emissions of the different sectors WSPA opposes this bigger proportion of the allowance budget going to the electrical distribution utilities at the expense of the industrial sectors. This makes the utility portion of allocation bigger than their portion of emissions (i.e. 59 percent of allocation vs. 56 percent of emissions) WSPA believes it is critical that all sectors are treated equitably and that all industry including the petroleum industry be provided the same recognition for energy efficiency and early reduction as is given to the electricity distribution utility sector. (WSPA3)

Response: We believe the dispensation of value to the electric sector is equitable and appropriately accounts for the emissions attributable to the electric sector. The purposes for allocating allowances to electric distribution utilities are fundamentally different than those for allocating allowances to the industrial sources. Accordingly, the method of apportioning that value is fundamentally different. With that said, we believe that the establishment of benchmarks in the industrial sector does adequately take into consideration factors such as energy efficiency, which are important for maintaining the incentive for entities to invest in cost-effective emissions reductions.

I-7. Comment: In section 95870(d), The Modified Text provides that the “allowances available for allocation to electrical distribution utilities shall be 97.7 million multiplied by the cap adjustment factor in Table 9.2 for each budget year 2013-2020.” NCPA supports this modification that takes into account 90 percent of the 9.67 MMT that is attributable to electricity from cogeneration facilities purchased by electricity distribution utilities. Including this amount in the allowances attributable to the electrical distribution utilities is appropriate, as independently verified by CARB staff using publicly available data. NCPA recommends that this section include a specific reference to Table 9-3. It is in this table that the actual percentage of allowances to be allocated to the electrical distribution utilities for 2013-2020 is set forth, yet Table 9-3 is not actually referenced in the body of the Proposed Regulation. (NCPA3)

Response: We believe that the changes made to section 95892(a) in the second 15-day changes to the regulation address the concern raised by the commenter.

I-8. Comment: Western understands that when determining a utility’s allocation of allowances, CARB will assume the RPS obligation in a utility’s resource mix even if that utility has not reported its RPS or is not under an RPS obligation. The assumed RPS obligation used by CARB will effectively reduce the amount of unspecified resources, and subsequently the allowances allocated to that utility. Western is not required to comply with California’s RPS. However, Western’s primary mission is to market the power generated from the Bureau of Reclamation's hydro generation facilities. The Sierra Nevada Region markets approximately 2,500 GWh annually to its end-use customers. On average, approximately 50 percent of that load is served with large hydro resources, a null greenhouse emitting resource. Western understands the goal under both the RPS and the Cap and Trade is to reduce greenhouse gas emissions. Western is already serving its load with an average of 50 percent greenhouse gas emission-free resources (well above the RPS requirements) and, therefore, should be allocated allowances based on its total reported unspecified resources. (WAPA2)

> **Response:** We believe that it is important to the integrity of the cap-and-trade program that all utilities have an incentive to continue to reduce their emissions intensity and that the customers of those utilities which have invested in costly renewables are adequately compensated for the actions taken on their behalf. Two important and related principles for the allocation to the electric sector were recognizing early actions made by individual utilities to reduce GHG emissions and the expectation that all electric distribution utilities would continue to aggressively reduce their emissions intensity in accordance with California's 33 percent RPS goals. As a means of binding all parties to this condition, the free allocation to each electric distribution utility was designed to decline by a factor reflecting this expected investment in eligible renewables. In this way, utilities that are already invested in renewables may be assured of a level playing field, because industrial, commercial, and residential consumers are not given an additional incentive to purchase power from utilities that do not comply with the RPS. No electric distribution utilities, except those for which incremental decrease in their emissions intensity is not practicable due to nearly complete reliance on zero GHG resources, were exempted from this method of allocation. While WAPA has historically relied on hydroelectric resources for a large share of its total end-use customer load, a greater investment in zero GHG resources is achievable. Further, without the assessment of the 33 percent RPS, we project that zero GHG resources will make up less than a majority or WAPA's resource mix in the future. Therefore, the standard allocation method was applied to WAPA.

I-9. Comment: The assumptions in the methodology for allocating allowances to utilities are clear that: 1) GHG costs will be incurred by fossil generators; 2) utility customers should see/incur such GHG costs; and 3) allocations are intended to cover these costs the utility pays to the generator. Yet, as currently written only the first will occur. This is clearly an inconsistency/error that must be fixed. Wellhead believes there is a very simple solution within the construct of the proposed regulations that is fully consistent with the proposed regulations and is consistent with the policy objective of making the cost of GHG emissions transparent. The solution 1) takes account of the fact that the free allocation methodology assumes all of the fossil generation in a utility's portfolio will have a GHG cost that is being passed through to its customers and 2) builds on the inclusion of a "beneficial holding relationship" in the proposed regulation. Further, the proposal encourages discussions that could lead to renegotiations before the program starts, improves the incentives for a successful outcome by providing clear guidance as to what CARB expects, and accounts in advance for the chance those discussions are not fruitful. Accordingly and to that end, Wellhead recommends adding a new subparagraph (4) to section 95834(a) of the proposed Regulations. This addition to the Regulations provides clear direction on a backstop approach to addressing the AB 32 contract problem while also eliminating the inconsistency/error in the proposed regulations free allowance allocation methodology. The result will support the clear objectives of AB 32 to reduce GHG emissions with regulations/programs that make the full cost of GHG emissions transparent to consumers. Modify section 95834(a) as follows:

> (4) In the event there is a long-term contract for the sale of electricity at wholesale to a distribution utility which:
>
> > i. does not directly or indirectly provide or refer to GHG costs either explicitly or through a CPUC authorized pricing basis that includes GHG costs;
> > ii. was fully executed before the final approval of AB 32 (September 27, 2006); and
> > iii. has not been renegotiated and approved by the appropriate regulatory authority as of January 1, 2012 to address GHG costs, then, a beneficial holding relationship is deemed to exist pursuant to section 95834(a)(1)(A) without further action. The electric distribution utility party to that long-term contract shall purchase and hold allowances for the eventual transfer to the other party to the long-term contract for the sole purpose of supplying that other party with compliance instruments to cover emissions resulting from deliveries under the long term power supply contract. (WEC2)

Response: We did not make this change. We believe that contract issues are best solved by the counterparties to those contracts. However, we understand that the CPUC will be discussing the treatment of generators who have long-term, fixed-price contracts with investor-owned utilities when the investor-owned utilities received allowances for expected carbon costs from this generation.

That said, in Resolution 11-32 the Board directed the Executive Officer to monitor progress on bilateral negotiations between counterparties with existing contracts that do not have a mechanism for recovery of carbon costs associated with cap-and-trade for industries receiving free allowances pursuant to Section 95891, and to identify and propose a possible solution, if necessary. For fixed-price contracts between independent generators and investor-owned utilities, the Board further directed the Executive Officer to work with the California Public Utilities Commission to encourage resolution between contract counterparties.

Accurate Accounting/Reporting

I-10. (multiple comments)

Comment: In section 95890 (page A409), ARB proposes that an EDU is eligible to receive a direct allocation of allowances "if it has complied with the requirements of the Mandatory Reporting Regulation (MRR) and has obtained a positive or qualified positive emissions data verification statement on its sales number for the prior year pursuant to MRR." While LADWP has every intention to comply with the requirements of MRR, it appears that this provision is vague and potentially unnecessarily punitive. If a covered entity has failed to comply with the emissions reporting requirements, penalty provisions are available to ARB within the MRR itself. ARB also has the ability to assign emissions to a covered entity in the absence of verified emissions. LADWP requests clarification as to the intent of this requirement to ensure that eligibility for a direct allocation cannot be obstructed by a minor or temporary setback associated with MRR verification, and that enforcement provisions for emissions verification are separated from the allocation rules. (LADWP4)

Comment: Section 95890 states that in order to be eligible for direct allocations an electrical distribution utility must have "complied with the requirements of the MRR" and "obtained a positive or qualified positive emissions data verification statement for the prior year pursuant to the MRR." These provisions should be removed. Table 9-3 entitled "Percentage of Electric Sector Allocation Allocated to Each Utility" identifies by name each utility that will receive a direct allocation of allowances. Being an electrical distribution utility as defined in section 95802(a)(82) and, as a result, being identified in Table 9-3 in itself establishes the eligibility of the utility to receive an allocation of allowances calculated in accordance with section 95870(d). Adding additional conditions that the utility must have "complied with the requirements of the MRR" and "obtained a positive or qualified positive emissions data verification statement for the prior year pursuant to the MRR" would expose the utility to a duplicative and harsh punishment—loss of its allocation of allowances—if it failed to meet those conditions.

The first requirement that the utility must have "complied with the requirements of the MRR" is vague. An entity could be deemed to be non-compliant with the MRR for a variety of reasons, including being late with reports, including inaccurate data in reports, or failure to retain records as required. The MRR already establishes penalties for these infractions. Imposing the additional penalty of denying the utility its allocation of allowances would add a duplicative and unduly disproportionate penalty to the penalties already established in the MRR.

The second requirement that the utility must have "obtained a positive or qualified positive emissions data verification statement for the prior year pursuant to the MRR" is more specific but equally problematic. While electrical distribution utilities expect to receive positive or qualified positive emission data verification statements without exception, the receipt of an adverse emission data verification statement cannot be ruled out. Section 95107 of the MRR establishes penalties for submitting verification reports late and for including inaccurate information in such reports. Again, the additional penalty of denying the utility its allocation would be duplicative and grossly disproportionate. It would be egregious to deny an allocation to a utility, forcing the utility to purchase allowances on the market to cover its compliance obligation. Imposing such a harsh as penalty would not be consistent with the goal of enabling each utility "to fully compensate their consumers for the costs associated with the cap-and-trade program." Compare the situation of having an adverse verification emissions report to the situation in which emissions are reported and verified accurately, but insufficient allowances are surrendered to cover them. In the latter case, an electrical distribution utility must surrender four compliance instruments for every one that is short under section 95857(b)(2) and may be subject to additional financial penalties under section 96014. In the former case, an entity could surrender compliance instruments to completely cover the emission obligation for a year with an adverse emissions statement and then forfeit an entire year's allocation of compliance instruments for the following year in addition to bearing penalties for inaccuracy or failure to report properly. This would be excessive and unfair. Utilities should not be required to have "complied with the requirements of the MRR" and "obtained a positive or qualified positive emissions data verification statement for the prior year pursuant to the MRR" to be eligible for the allocation provided to them in Table 9-3. Being named and provided an allocation in Table 9-3 should, in itself, establish each utility's eligibility for an allocation. Modify section 95890(b) as follows:

~~(b) Eligibility Requirements for Electrical Distribution Utilities. An electrical distribution utility shall be eligible for direct allocation of California GHG allowances if it has complied with the requirements of MRR and has obtained a positive or qualified positive emissions data verification statement for the prior year pursuant to MRR.~~ (SCPPA6)

Comment: Section 95890 on page 109 states that in order to be eligible for direct allocations an electrical distribution utility must have "… complied with the requirements of the MRR…" and "… achieved a positive or qualified positive emissions data verification statement for the prior year pursuant to the MRR." This provision appears to be a holdover from when ARB was considering an allocation mechanism that depended upon verified sales data and emissions data from prior years. In the 15-day language, the allocation to electric distribution utilities is determined up-front, and does not depend in any way on an entities reported emissions from the prior year, verified or otherwise. While compliance requires surrender of compliance instruments to cover verified emissions, or the amount assigned by the Executive Officer in the event of an adverse verification, this compliance is essentially independent going forward from the allowance allocation process. Section 95890(b) in effect represents a significant implied potential penalty and should be removed from the regulations. The requirement for "compliance with the MRR" is too vague. An entity could be deemed in non-compliance with the MRR for a variety of reasons, including being late with reports, including inaccurate data in reports, or failure to retain records as required. In each of these cases, the MRR already establishes penalty provisions. This requirement should be removed. The second requirement is more specific but equally problematic. While electrical distribution utilities expect to achieve positive emission data verification statements in general, the event of an adverse emission data verification statement cannot be ruled out. In such an event, it seems an egregious penalty to not provide direct allocations in the following year, forcing the electrical distribution utility to purchase allowances on the market to cover its compliance obligation. Such a penalty is not consistent with the goal of avoiding an undue compliance burden being placed on utility ratepayers. Section 95107 of the MRR already establishes penalties for submitting verification reports late and for including inaccurate information in such reports. Additional penalties for these violations are not necessary. This requirement should be removed. Compare the situation of having an adverse verification emissions report to the situation where emissions are reported and verified accurately, but insufficient allowances are surrendered to cover them. In the latter case, an electrical distribution utility must surrender four compliance instruments for every one that is short, and is subject to additional financial penalties. In the former case, an entity could surrender compliance instruments to completely cover the emission obligation for a year with an adverse emissions statement, and in effect be required to surrender an entire year's worth of compliance instruments in the following year, in addition to any penalties for inaccuracy or failure to report properly. This is clearly not a fair penalty. There is no reason to have an eligibility test for direct allocations that is related to compliance with the MRR or achievement of a positive or qualified positive emissions statement for the prior year. Whether one year's emissions are verified accurately or not, an electrical distribution utility still has a compliance obligation for the following year, and still has ratepayers subject to compliance costs without direct allocations. The best solution to this problem is to simply excise Section 95890(b) in entirety. Modify section 95890(b) as follows:

> ~~(b) Eligibility Requirements for Electrical Distribution Utilities. An electrical distribution utility shall be eligible for direct allocation of California GHG allowances if it has complied with the requirements of the MRR and has obtained a positive or qualified positive emissions data verification statement on its sales number for the prior year pursuant to the MRR.~~ (SMUD3)

Comment: Section 95890(b) states that in order to be eligible for direct allocations an electrical distribution utility must have "complied with the requirements of MRR" and "obtained a positive or qualified positive emissions data verification statement for the prior year pursuant to MRR." This provision should be removed now that ARB has decided to specify the allocations for electric distribution utilities for each year in Table 9-3 in section 95892. The purpose of this subsection was to update sales-based allocations with the latest data if the allocations were to transition to a sales-based allocation as recommended by the CPUC and the CEC. The decision in the 15-day modifications to not use sales or emissions as a basis means this subsection is not necessary and should be deleted. Modify section 95890(b) as follows:

> ~~(b) Eligibility Requirements for Electrical Distribution Utilities. An electrical distribution utility shall be eligible for direct allocation of California GHG allowances if it has complied with the requirements of MRR and has obtained a positive or qualified positive emissions data verification statement for the prior year pursuant to MRR.~~ (SEMPRA3)

Comment: Section 95890(b) would require electrical distribution utilities to comply with the MRR and have positive verification in the previous year in order to get free allowances each year. As discussed in Appendix A, an electrical distribution utility should be eligible to receive the allocation of allowances if they are listed in Table 9-3; accordingly, NCPA believes that section 95890(b) is unnecessary. For one thing, Appendix A of the Notice sets forth the requirements for electrical distribution utilities to qualify for allocation of allowances under the Program, and the qualification is not based on the amount of emissions reported under the MRR. Secondly, the MRR contains a wide range of reporting requirements; there is no single MRR rule that would apply to all electrical distribution utilities, and some electrical distribution utilities will be subject to different provisions of the MRR. Therefore, mandating compliance with the MRR is vague and could be ambiguous. Likewise, there are a number of reasons why an entity that is required to obtain verification does not have a positive verification in time to qualify for the subsequent year's allowance allocation. Further, if the goal here is to incentivize compliance with the MRR, the MRR and Cap-and-Trade regulation are each replete with remedies available to CARB should they feel that the electrical distribution utilities are not meeting their reporting obligations, in addition to the requirement to surrender allowances for underreported emissions. Accordingly, NCPA agrees with the recommendation of the Joint Utilities that section 95890(b) be stricken entirely. Modify section 95890(b) as follows:

> ~~(b) "An electrical distribution utility shall be eligible for direct allocation of California GHG allowances if it has complied with the requirements of the MRR and has obtained a positive or qualified positive emissions data verification statement on its sales number for the prior year pursuant to the MRR."~~ (NCPA3)

Comment: If ARB decides that a provision on eligibility for electrical distribution utilities should be retained in section 95890 to parallel the section on eligibility for industrial facilities in section 95890(a). Modify section 95890(b) as follows:

> (b) Eligibility Requirements for Electrical Distribution Utilities. An electrical distribution utility shall be eligible for direct allocation of California GHG allowances if it meets the definition of "Electrical Distribution Utility" in section 95802(a)(82).~~has complied with the requirements of the MRR and has obtained a positive or qualified positive emissions data verification statement on its sales number for the prior year pursuant to the MRR.~~ (SCPPA6)

> **Response:** We disagree. It is critical that utilities, like all other covered entities, comply with the MRR and accurately report GHG emissions. We believe that accurate accounting is necessary to a successful cap-and-trade program. If EDUs did not comply, we would not have the data needed to determine an EDU's compliance obligation. Further, like all entities receiving free allocation, free allocation must be made conditional on a positive verification of reported emissions. This provision is necessary to avoid the fulfillment of false claims on and mis-apportionment of allowance value.

I-11. Comment: If CARB determines that it is necessary to continue to reference the provisions of the MRR in conjunction with eligibility to receive an allowance allocation, NCPA recommends that the provisions of section 95890(b) be revised to provide a reference to the "applicable" MRR provisions. Modify section 95890(b) as follows:

> (b) An electrical distribution utility shall be eligible for direct allocation of California GHG allowances if it has complied with the <u>applicable</u> requirements of the MRR and has obtained a positive or qualified positive emissions data verification statement on its sales number for the prior year pursuant to the MRR. (NCPA3)
>
> **Response:** We did not modify the section as proposed. It is unnecessary to qualify the eligibility requirement in this way because entities are not required to comply with any provisions that do not apply to them.

Community Choice Aggregation and Cooperatives

I-12. Comment: How will Community Choice Aggregators (CCA) that come into existence after 2008 receive electric utility allocations? Table 9-3, page A-124, did not list Marin Clean Energy (MCE) as a recipient of allowances. MCE is a current example of a CCA, but other local governments are investigating the feasibility of CCA. If new CCAs come online, is there a method to provide allocations to them? They should be required to return the value to their ratepayers as well. (CARBONSHARE2)

> **Response:** Thank you for the comment. We believe that section 95892(d)(4) as amended in the second 15-day changes to the regulation addresses the concern raised by the commenter.

I-13. Comment: The Regulation should be further modified to add "electrical cooperatives" to the definition key at the bottom of Table 9-3, or to change the POU designation to "publicly owned utilities and electrical cooperatives." (NCPA3)

> **Response:** We agree. We added "electrical cooperatives" to the definitions.

Confidentiality of Data for Appendix A

I-14. (multiple comments)
Comment: NCPA seeks clarification from CARB regarding the tables included in the Revised Appendix A, and the correlation to Table 9-3 in the Regulation in order to ensure that all of the figures expressed in the document correctly represent the appropriate number of allowances to be allocated to each of the electrical distribution utilities. On July 27, CARB issued a Revised Appendix A. The tables and summaries in the Revised Appendix that correspond to Table 9-3 have been updated from what was provided on July 25. Before parties can comment on the specific numbers set forth in Table 9-3 (as opposed to the underlying methodology addressed in Appendix A), CARB must provide stakeholders with clarification regarding the finality of the tables. The

underlying spreadsheets that support the final figures should also be provided. Stakeholders should be able to submit comments and input to CARB on this matter once such clarification is provided. (NCPA3)

Comment: ARB indicates in Appendix A that staff has created an ARB allocation model based on the Joint Utilities' 2010 database. LADWP understands that ARB's allocation model is yet to be made publicly available for review and validation. It would be beneficial to have the ARB allocation model outputs validated to ensure that any unintended formula errors are identified and corrected. Additionally, LADWP recommends that the final allocation schedule, as corrected, be incorporated directly into the regulation in section 95892. (LADWP4)

> **Response:** We did not provide further detail regarding the dispensation of allowance value to the electric distribution utilities. Many of the data provided for this portion of the regulation were provided to us with the understanding that they are trade-sensitive and confidential. Similar to the allocation to EITE industry, we have determined that we cannot release these data.

Accounts, Distribution, and Allocation Timing for EDUs

I-15. (multiple comments)
Comment: Section 95870(d) states that the Executive Officer will place allocations in the "holding accounts" of each utility, on or before January 15 of each calendar year pursuant to section 95892. Several clarifications are needed here. First, Table 9-3 in the 15-day language includes the percentage amounts that take the overall electric sector allocation, 97.7 million metric tons times the adjustment factors in Table 9-2, as stated in section 95870(d), and allocate these annual amounts to each of the 57 electric distribution utilities identified in the table. However, no language in the Regulations themselves states that Table 9-3 is to be used in this manner, and this should be corrected for clarity. Second, the placement of allowances in the "holding accounts" of each eligible utility is inconsistent with section 95892, in which the Executive Officer is to place allowances in either the "limited use holding accounts" of each utility or, for POUs, in compliance accounts as designated in section 95892(b)(2). Per section 95892, no allowances are to be placed in a utility's "holding account." Third, it may be useful to specify with more certainty when allowances are to be placed in the appropriate accounts, for two reasons. With the delay of the Cap and Trade program until 2013, there is some uncertainty about when allowances will be distributed for utilities (and industrial regulated parties) prior to that year. With two advance auctions scheduled for the second half of 2012, the Regulations imply that at least for investor owned utilities the Executive Officer will place allowances in their limited use holding accounts at least six months prior to January 15, 2012. Presumably, industrial regulated parties would also be distributed allowances prior to the auctions, so that they have certainty about their need for allowances and can decide whether to and how to participate. While this early placement is allowed by the "on or before" language in the Regulations, greater certainty about how this will work would be useful. In addition, given the "or before" language in the Regulations, there is a degree of risk for POUs,

which are expected pursuant to section 95892(b)(2) to inform the Executive Officer "...at least 90 days prior…" to receiving a direct allocation of allowances how those allowances should be dispersed to the acceptable accounts. POUs may find themselves in inadvertent violation of the regulations if the Executive Officer decides to exercise the "or before" option and the POU no longer has 90 days with which to inform about proper placement. Finally, the term "eligible" would no longer be needed here, should ARB accept the proposed change to section 95890 above. Modify section 95870(d) as follows:

> (d) Allocation to Electrical Distribution Utilities. The Executive Officer will place an annual individual allocation in the ~~holding~~ appropriate accounts of each ~~eligible~~ electrical distribution utility on ~~or~~ before July 15, 2012, or first business day thereafter, for vintage 2013 allowances and January 15, or first business day thereafter, of each calendar year from 201~~3~~4-2020 pursuant to section 95892. Allowances ~~available for allocation~~ allocated to electrical distribution utilities shall be 97.7 million multiplied by the cap adjustment factor in Table ~~9.2~~ 9-2 for each budget year 2013-2020, multiplied by the utility allocation factors in Table 9-3 for each year. (SMUD3)

Comment: Section 95870(d) should be revised to correctly identify the accounts into which the Executive Officer will place the allowances that are allocated to electrical distribution utilities. Currently, the section incorrectly states that the Executive Director shall place the allowances that are allocated to electrical distribution utilities in the "holding account" of each utility. The section should be revised to state that the allowances shall be placed either in the utility's limited use holding account in accordance with section 95892(b)(1) or in the utility's compliance account in accordance with section 95892(b)(2). Additionally, section 95870(d) should be revised to provide that the allowances that are allocated to the electric sector each year shall be allocated among the electrical distribution utilities on the basis of the percentage allocation factors specified for each utility in Table 9-3. Currently, the section identifies the total amount of allowances that shall be available for allocation to the electrical distribution utility sector each year but does not take the next step of identifying how the allowances will be allocated among the electrical distribution utilities within the sector. Modify section 95870(d) as follows:

> (d) Allocation to Electrical Distribution Utilities. The Executive Officer will place an annual individual allocation either in each eligible electrical distribution utility's limited use holding account in accordance with section 95892(b)(1) or in its compliance account in accordance with section 95892(b)(2)~~in the holding account of each eligible electrical distribution utility~~ on or before January 15 of each calendar year from 2013-2020 pursuant to section 95892. Allowances available for allocation to electrical distribution utilities each budget year shall be 97.7 million metric tons multiplied by the cap adjustment factor in Table 9-2 for each budget year 2013-2020. The allowances allocated to each electrical distribution utility each budget year shall be the amount allocated to the electrical

distribution utilities for the budget year multiplied by the percentage allocation factors specified in Table 9-3. (SCPPA6)

Comment: Section 95870(d) states that electric distribution utilities will be allocated allowances on or before January 15th of each calendar year starting in 2013. ARB should provide an allowance allocation date for the initial auctions that will take place in the second half of 2012 (for 2013 allowances). In addition, PG&E proposes that allocation occurs at least prior to the date in which electric distribution utilities are required to consign allowances to the auction, prior to December 1st of each calendar year would suffice. (PGE4)

> **Response**: We updated section 95870(d). The Executive Officer will place allowances in limited use holding accounts. We updated the timing of allowance allocation activities in section 95870(a-d) in response to stakeholder comment. Allocation to accounts controlled by the Executive Officer will now occur immediately after the creation of these accounts. Allocation to electrical distribution utilities and industrial covered entities will now occur in November of the year prior to the allowance budget year being distributed. A special allocation of 2013 vintages to electrical distribution utilities is now planned in July 2012, to allow for consignment auctions by utilities of one-third (one-sixth at each of two auctions) of 2013 allowances in 2012.

I-16. Comment: Section 95892(b)(2) states that Publicly Owned Utilities must inform the Executive Officer in which accounts they want allowances for the vintage year to be placed, at least 90 days prior to receipt of the allowances. The Regulations allow POUs to request placement of allowances in their limited use holding accounts, their compliance accounts, or the compliance accounts of a "Joint Powers Agency in which the electrical distribution utility is a member and with which it has a power purchase agreement." There are two clarifications that would be beneficial here. First, unlike section 95892(b)(1), there is no language for the POUs or electrical cooperatives (note there is also a misspelling of the word "cooperative") that states that the Executive Officer shall place allowances in the accounts as previously informed by the POUs. Second, additional flexibility is necessary for situations in which a publicly owned utility is the sole procurer of power from several JPAs associated with specific power plants. In this situation, the POU is in effect operating and dispatching the facilities, and the amount of allowances needed for compliance by a specific JPA entity may vary significantly from one year to the next depending upon system conditions in the POU's territory. These system conditions are not well known in advance. For example, it is not known in advance whether a year will be particularly wet or dry or hot or cool, and these differing conditions can lead to large changes in the need to dispatch particular JPA associated units. Modify section 95892(b)(2) as follows:

> (2) Publicly Owned Electric Utilities or Electrical Cooperatives. At least 90 days prior to receiving a direct allocation of allowances, publicly owned electric utilities or Electrical Cooperatives will inform the Executive Officer of the share of their allowances that is to be placed: in the allowed accounts in 95892(b)(2)(A) and (B). Upon receiving the publicly owned utility or electrical cooperative's

information, the Executive Officer shall place allowances in the accounts as indicated.

(A) In the publicly owned electric utility's or Electrical Cooperative's compliance account or the compliance account of a Joint Powers Agency in which the electrical distribution utility is a member and with which it has a power purchase agreement; or

(B) In the publicly owned electric utility's or Electrical Cooperative's limited use holding account.

(C) With the approval of the Executive Officer, a publicly owned utility or electrical cooperative may move allowances in the compliance account of a Joint Powers Authority with which it alone has a power purchase agreement to the compliance account of another Joint Powers Authority with which it alone has a power purchase agreement prior to the surrender deadlines in Section 95856(d). (SMUD3)

Response: We corrected the typographical error in section 95892(b)(2). We also modified the language in sections 95892(b)(2)(A) and (B) in a way that we believe provides POUs with the flexibility requested. We did not make the change requested to insert section 95892(b)(2)(C) because entities will not have the ability to remove compliance instruments from compliance accounts. However, the revisions to section 95892(b)(2)(A) allow the POUs to request the Executive Officer to place directly allocated allowances into the compliance accounts of Joint Power Agencies. We believe that this change will give the POUs the flexibility they need without wholesale changes to the structure of the accounts system.

Calculation and Use of Allowance Value

I-17. Comment: CARB should clarify its intent in sections 95892(d) and (e) with regard to the use of the terms "auction value," "allowance value," and "monetary value." These terms are used interchangeably in some context, yet they have distinct meanings. This clarification is necessary because these sections place specific requirements on electrical distribution utilities, and the scope of the requirements must be clearly understood. (NCPA3)

Response: Thank you for the comment. Definitions are provided in the regulation to clarify the meaning of these terms. We believe the usage is consistent with definitional meanings.

I-18. Comment: Section 95892(a) requires that allowances allocated to Electrical Distribution Utilities must be used exclusively for retail ratepayers. WSPA recommends that the language be clarified to include industrial ratepayers in the retail ratepayers. Further WSPA recommends that Electrical Distribution Utilities also participate in the revenue distribution for other purposes such as to address the environmental justice requirements. (WSPA3)

Response: Thank you for the comment. We expect that some fraction of the value allocated to electric distribution utilities may be used for industrial customers. We are awaiting the conclusion of the CPUC proceeding on the use of allowance value before moving forward with any additional changes to our guidance on the use of allowance value.

I-19. (multiple comments)
Comment: Section 95892(e)(2) states that Publicly Owned Utilities must calculate the value of allowances placed into their compliance accounts directly, and report annually on the use of that allowance value. SMUD believes that the calculation of allowance value is vague, and should be clarified, and that ARB must clarify that the use of allowance value for retail compliance, as established in section 95892(b)(2). ARB can avoid differential calculation of 'allowance value' by the POUs in the state, each using a different averaging technique (e.g. – weighted differentially) by performing the calculation averaging the four quarterly auction prices itself, and providing the result to use. Modify section 95892(e)(2) as follows:

(e) Reporting on the Use of Auction Proceeds and Allowance Value. No later than June 30, 2013, and each calendar year thereafter, each electrical distribution utility shall submit a report to the Executive Officer describing the disposition of any auction proceeds and allowance value received in the prior calendar year. This report shall include:

(1) The monetary value of auction proceeds received by the electrical distribution utility;

(2) How the electrical distribution utility's disposition of such auction proceeds complies with the requirements of this section and the requirements of California Health and Safety Code sections 38500 et seq;

(3) The monetary value of allowances received by the electrical distribution utility which were deposited directly into its compliance account. ~~The~~ <u>ARB shall calculate the</u> value of these allowances ~~shall be quantified~~ based on the average market clearing price of the four quarterly auctions held in the same calendar year ~~that the~~ <u>of the vintage of the</u> allowances ~~are allocated~~; and

(4) How the electrical distribution utility's disposition of the monetary value of allowances, deposited directly into its compliance account, complies with the requirements of this section and the requirements of California Health and Safety Code sections 38500 et seq. <u>Use of allowance value for compliance associated with retail load of the publicly owned utilities complies with the requirements of this section.</u> (SMUD3)

Comment: The Utilities recommend striking section 95892(e)(4), as it does not provide any unknown or additional information to CARB, is not needed to monitor the use of allocated allowances, and creates unnecessary uncertainty and burden to a process that already creates significant administrative work. Allowances deposited into a compliance account may only be used in a single manner—to be retired to meet an entity's compliance obligation. Thus, no report is necessary to provide data regarding the purpose or use of such allowances or allowance value. Modify section 95892(e)(4) as follows:

> ~~(4) How the electrical distribution utility's disposition of the monetary value of allowances, deposited directly into its compliance account, complies with the requirements of this section and the requirements of California Health and Safety Code sections 38500 et seq.~~ (MID3)

Response: We did not strike the text as recommended by the commenter. This reporting is necessary to achieve a full picture of how all allowance value distributed to electrical distribution utilities is used. The flexibility to directly use freely allocated allowances to meet a compliance obligation is unique to the POUs. We desire a close accounting of how many allowances are used in this fashion so that we may better understand how this affects carbon pricing from these generators.

1-20. (multiple comments)
Comment: Section 95892(f) should be amended to address the situation of several SCPPA members who are members of the California Independent System Operator (CAISO). CAISO members are required to sell the electricity they generate or import into the CAISO's market and then bid the electricity back in a wash transaction in order to use the electricity they generate to serve their native load. Section 95892(f) as currently written would prohibit the SCPPA members of the CAISO from using directly allocated allowances that the Executive Officer places in their compliance accounts to meet the compliance obligation associated with the electricity they generate or import to serve their native load but which must be sold into the CAISO market and then bid back in a wash transaction. In order to permit the SCPPA members of the CAISO to use their directly allocated allowances to meet the compliance obligation associated with the electricity they generate or import to serve their native load, section 95892(f) should be revised. Modify section 95892(f) as follows:

> (f) Prohibited Use of Allocated Allowance Value. Use of the value of any allowance allocated to an electrical distribution utility, other than for the benefit of retail ratepayers consistent with the goals of AB32 is prohibited, including use of such allowances to meet compliance obligations for electricity sold into the California Independent System Operator markets <u>in excess of the electricity needed to meet the electrical distribution utility's native load in the same hour</u>. (SCPPA6)

Comment: The Utilities recommend striking section 95892(f) as it is duplicative of section 95892(a). Further, it is unclear as to the rationale for excluding the value of free allowances from being used for electricity sold into the California Independent System Operator (CAISO). While the Utilities understand that the CAISO has no compliance obligation under the Cap and Trade program, it would seem difficult, if not impossible, to manage and keep an accurate accounting of this distinction. In addition, the Utilities are concerned this exclusion could create a huge problem for entities that must sell into the

CAISO markets because they do not own transmission from their generation to their load. This clause would be harmful due to the nature of the CAISO markets (CAISO does not allow point to point energy deliveries, only imports/exports at various nodes). Any utility that owns remote generation and relies on the CAISO markets for energy delivery rather than utility-owned transmission would be penalized at the expense of their ratepayers who already pay significant CAISO costs. Modify section 95892(f) as follows:

> ~~(f) Prohibited Use of Allocated Allowance Value. Use of the value of any allowance allocated to an electrical distribution utility, other than for the benefit of retail ratepayers consistent with the goals of AB32 is prohibited, including use of such allowances to meet compliance obligations for electricity sold into the California Independent System Operator markets. (~~MID3)

Comment: IOUs must consign all allocated allowances and use that revenue for the benefit of customers and cannot use revenues for any other purpose. Modify section 95892(f) as follows:

> (f) Prohibited Use of Allocated Allowance Value. Use of the value of any allowance allocated to an electrical distribution utility, other than for the benefit of retail ratepayers consistent with the goals of AB 32 is prohibited~~, including use of such allowances to meet compliance obligations for electricity sold into the California Independent System Operation markets.~~ (PGE4)

Comment: The Proposed Regulation clearly expresses CARB's intent that the total value of the allowances allocated to electrical distribution utilities should be used for the benefit of customers and to further the objectives of AB 32. This requirement is further refined by the oversight of the California Public Utilities Commission IOUs or the local governing boards of POUs and electrical cooperatives (section 95892(a), (d), and (e)). Accordingly, section 95892(f), which places further restrictions on the use of the funds for California Independent System Operator (CAISO) transactions, should be stricken, as it fails to recognize the manner in which energy transactions through the CAISO BA work. For entities such as NCPA that have all of their transactions go through the CAISO BA, including self scheduled energy that is delivered directly to load, this prohibition would place an unreasonable constraint on utility operations. Due to the CAISO's rules for scheduling and bidding, tracking the various permutations of such transactions would be virtually impossible. The prohibition on using allowances to meet surrender obligations for sales into the CAISO appears to be intended to address the sale of excess energy. However, as drafted, it creates untenable restriction on utility operations and should be deleted. Pursuant to the provisions of section 95852(e), electrical distribution utilities will be providing detailed reports regarding the use of the allowance value. Those reports must reflect the beneficial use of the value, which will allow CARB to verify compliance with the provisions of the Regulation. The restriction in section 95852(f) does nothing to further the goals of the section 95852(a) and should be stricken from the Proposed Regulation. Modify section 95852(f) as follows:

~~(f) Prohibited Use of Allocated Allowance Value. Use of the value of any allowance allocated to an electrical distribution utility, other than for the benefit of retail ratepayers consistent with the goals of AB32 is prohibited, including use of such allowances to meet compliance obligations for electricity sold into the California Independent System Operator markets.~~ (NCPA3)

Response: 95892(d)(5), which was formerly 95892(f), imposes specific prohibitions on some uses of freely allocated allowances and auction proceeds. The intent of this language is to guarantee that all bids into the CAISO markets correctly include the generator's emissions cost in the generator's CAISO market bid price. Specifically, POUs that wish to transfer allowances to generators that sell into the CAISO market will have to purchase those allowances at the allowance auction or in the secondary market to ensure the transferred allowance is correctly valued and that freely allocated allowances are not used to suppress CAISO bid prices.

POUs are able to use their freely allocated allowances to directly meet the compliance obligation for generators that do not sell into the CAISO market. We understand some generators controlled by POUs may sell their electricity into the CAISO market, and then purchase it back out of the market to meet their load, due to transmission constraints. We do not consider this a special case. The POUs may not transfer freely allocated allowances to meet the compliance obligation of those generators involved in these wash transactions.

I-21. Comment: It is not clear how CARB intends to ensure achievement of the goal of minimizing leakage in the utility allowance allocation process. Neither the Regulation nor Resolution 10-42 expressly direct the CPUC or municipalities to ensure that the allowance allocation methodology protect EITE entities and thereby minimize leakage. CARB is fully within its jurisdiction to condition its provision of allowances to the utilities on treatment of EITE ratepayers in a way that will minimize leakage and also preclude any chance of double-recovery. The CPUC's role is clearly limited under Public Utilities Code section 701 to regulating California's public utilities. The goal of minimizing leakage through the protection of EITE entities, however, is unrelated to public utilities. It is a goal directed toward preventing shifts of manufacturing activity to facilities outside of the state and thereby creating emissions leakage. While it is possible that the CPUC will strive to limit leakage, this is not its traditional role. Accordingly, to ensure that electricity sector allowances are used in a manner that fulfills AB 32 objectives, CARB must condition its allowance allocation to the electricity sector on the use of allowance value to offset EITE indirect GHG compliance costs reflected in utility power rates. Moreover, the Regulations should clarify that if the auction value of the 97.7 MMT allowances is not used to offset EITE indirect costs, CARB will withhold allowances needed to cover EITE indirect costs from the electricity sector allowance allocation so that the allowances can be allocated to EITE customers directly by CARB. Modify section 95892(d)(3) as follows:

(3) Auction proceeds obtained by an electrical distribution utility shall be used exclusively for the benefit of retail ratepayers of each electrical distribution utility, consistent with the goals of AB 32, and may not be used for the benefit of entities or persons other than such ratepayers.

(A) Investor owned utilities shall ensure equal treatment of their own customers and customers of electricity service providers and community choice aggregators.

(B) To the extent that an electrical distribution utility uses auction proceeds to provide ratepayer rebates, it shall provide such rebates with regard to the fixed portion of ratepayers' bills or as a separate fixed credit or rebate.

(C) To the extent that an electrical distribution utility uses auction proceeds to provide ratepayer rebates, these rebates shall not be based solely on the quantity of electricity delivered to ratepayers from any period after January 1, 2012.

(D) Investor owned utilities shall use auction proceeds to offset the greenhouse gas compliance costs reflected in the rates charged to energy-intensive, trade-exposed customers consistent with the goal of AB 32 to limit emission leakage. (EPUC2)

Response: We did not make the change. However, we expect that some fraction of the value allocated to electric distribution utilities may be used for leakage prevention from industrial sources that purchase electricity from electric distribution utilities. We are awaiting the conclusion of the CPUC proceeding on the use of allowance value before moving forward with any additional changes to our guidance on the use of allowance value.

Beneficial Holding Relationships

I-22. Comment: PG&E appreciates that ARB has recognized the need to allow electrical distribution utilities to claim a beneficial holding relationship under certain circumstances. However, PG&E is concerned that the new language specifies that a beneficial holding relationship for electrical distribution utilities requires the contract for electricity be "long-term." Electrical distribution utilities should be able to serve as the agent in a beneficial holding relationship for any contract for the delivery of electricity, regardless of length. Further, as the electrical distribution utility may be serving as the agent acquiring and holding compliance instruments for multiple second registered entities, it would be preferable to allow each second registered entity to allocate a portion of its holding limit to the electrical distribution utility, and to allow the electrical distribution utility to aggregate any such allocated holding limits. Modify section 95834as follows:

(a) A B~~b~~eneficial H~~h~~olding relationship exists when:

(1) An E~~e~~ntity holds C~~c~~ompliance I~~i~~nstruments in its H~~h~~olding A~~a~~ccount that are owned by a S~~s~~econd R~~r~~egistered E~~e~~ntity. The E~~e~~ntity acquires, holds, and ~~disposes of~~ transfers the C~~c~~ompliance I~~i~~nstruments based on instructions from or

an agreement with the S~~s~~econd R~~r~~egistered E~~e~~ntity. There are two types of participants in a B~~b~~eneficial H~~h~~oldings relationship:

(A) The agent in the B~~b~~eneficial H~~h~~oldings relationship is the registered entity holding C~~c~~ompliance I~~i~~nstruments owned by another E~~e~~ntity or to be transferred to another E~~e~~ntity under an agreement disclosed to ARB.

(B) The principal in the B~~b~~eneficial H~~h~~oldings relationship is the registered entity that owns the Ccompliance Iinstruments held by an agent or to whom the C~~c~~ompliance I~~i~~nstruments will be transferred under an agreement disclosed to ARB.

(2) An E~~e~~lectrical D~~d~~istribution U~~u~~tility informs ARB that ~~it has established an agreement~~ its contract for delivery of electricity includes the option to serve as the agent in a B~~b~~eneficial H~~h~~olding relationship pursuant to section 95834(a)(1)(A) to purchase and hold A~~a~~llowances for the eventual transfer to a S~~s~~econd R~~r~~egistered E~~e~~ntity with whom it has ~~a long-term~~ the contract. ~~for the delivery of electricity for the sole purpose of supplying the second entity with compliance instruments to cover emissions resulting from satisfying the electricity contract.~~ These Allowances will be transferred to the Second Registered Entity's Compliance Account for the sole purpose of supplying the second entity with Compliance Instruments to cover emission obligations per the contract.

(A) This disclosure shall include the facility ID(s) associated with the contract and must be made to ARB prior to any such purchases~~, and must include the terms of the contract governing the eventual transfer~~. The disclosure shall also specify a percentage of the Second Registered Entity's Holding Limit as agreed upon by both parties that shall be allocated to the Electric Distribution Utility serving as the agent in the Beneficial Holdings relationship.

(B) An E~~e~~ntity serving as agent in this type of a B~~b~~eneficial H~~h~~olding relationship may not also serve as the agent in a B~~b~~eneficial H~~h~~olding relationship with an E~~e~~ntity with whom it does not have a ~~long-term~~ contract for the delivery of electricity. An Electrical Distribution Utility serving as an agent in a Beneficial Holding relationship shall be able to aggregate any Holding Limits allocated to it by Second Registered Entities. (PGE4)

Response: We reject the request to transfer a portion of one entity's holding limit to another as impractical, since there is otherwise no corporate association. To implement this recommendation would require an entirely new process. However, we revised the language in section 95834 to allow two entities to inform the Executive Officer that they intend to operate a beneficial holding relationship. Allowances held under such an arrangement will be counted toward the principal's holding limit. This approach serves the same function as the proposal made in the comment, without introducing a new procedure.

I-23. Comment: Calpine opposes the proposed Regulation's new "beneficial holding relationship" because it further exacerbates the competitive disadvantage between independent power producers and IOUs by providing that IOUs' holding of allowances for their long-term contract generators will count against the holding limit of the generator. Calpine is disappointed that CARB would provide the utilities so much flexibility to manage their carbon risk and abide by the auction purchase and holding limits, while providing no such flexibility to the generators who are actually subject to a compliance obligation. Modify sections 95834(a)(2) and 95920(h) as follows:

> (2) An electrical distribution utility and a second registered entity with whom it has a contract for the delivery of electricity informs ARB that it has they have established an agreement for the utility to serve as the agent in a beneficial holding relationship pursuant to section 95834(a)(1)(A) to purchase and hold allowances for the eventual transfer to ~~a~~ the second registered entity ~~with whom it has a contract for the delivery of electricity~~ for the sole purpose of supplying the second entity with compliance instruments to cover emissions resulting from satisfying the electricity contract.
>
> (A) This disclosure must be made to ARB prior to any such purchases, and must include the terms of the contract governing the eventual transfer and a statement by the utility confirming its intention to transfer to the second entity the required number of allowances needed to fulfill the second entity's compliance obligations under sections 95855 and 95856 prior to the time they are due.
>
> (h) The application of the holding limit will treat beneficial holding by an agent as part of the holding of the owner, provided that, in the case of an electric distribution utility beneficially holding allowances on behalf of a second registered entity pursuant to section 95834(a)(2), the electric distribution utility and second entity have informed ARB in the disclosure required by said section 95834(a)(2) of the number of allowances that will be held on the second entity's behalf. (CALPINE3)
>
> **Response:** We understand the basic problem identified in the comment. However, instead of the language proposed by the comment, we added new language that will require both parties to a beneficial holdings relationship to (1) inform the Executive Officer of the existence of the relationship, and (2) give each party the right to approve all transactions made pursuant to the relationship. We believe that the replacement language satisfies the commenter’s concern.

Holding Limit and Exemptions

I-24. Comment: Section 95920(d)(2) refers to a “limited exemption” from the Holding Limit. However, in fact the amount calculated in the “limited exemption” provision is added to and forms part of the Holding Limit, rather than being an exemption to it. For clarity, the wording should be changed from “exemption” to “addition” to reflect the intended operation of this section. In section 95920(d)(2), it appears that subsections (B) to (H) are intended to act as a cap on the limited addition set out in subsection (A). This should be specified. Section 95920(d)(2)(B) refers to the most recent verified report received as of June 1, 2012. This will be the report on 2010 emissions, as the 2011 report will not be verified until later in 2012. SCPPA understands that section

95920(d)(2)(C) will operate to provide that, in October 2013, the limited addition would be [2010 + 2012] emissions. In October 2014, it would be [2010 + 2012 + 2013] emissions. In October 2015, it would be [2010 + 2012 + 2013 + 2014] emissions. SCPPA further understands that section 95920(d)(2)(H) will operate to provide that on December 31, 2015, for example, the limited addition would be [2010 + 2012 + 2013 + 2014] – [2013 + 2014] = [2010 + 2012] emissions. If this understanding is not correct, section 95920(d) should be clarified. Modify section 95920(d) as follows:

> (d) The holding limit will be calculated for allowances qualifying pursuant to section 95920(c)(1) as the sum of (1) and (2) below:
>
> (1) The number given by the following formula:
> Holding Limit = 0.1*Base + 0.025*(Annual Allowance Budget – Base)
> In which:
> "Base" equals 25 million metric tons of CO_2e.
> "Annual Allowance Budget" is the number of allowances issued for the current budget year.
>
> (2) A Limited Addition to~~Exemption from~~ the Holding Limit~~, is~~ calculated as follows:
>
> (A) The limited addition~~exemption~~ is the number of allowances which are exempt from the holding limit calculation after they are transferred by a covered entity or an opt-in covered entity to its compliance account, subject to the limitations set out in sections 95920(d)(2)(B) to (H) inclusive.
>
> (B) On June 1, 2012, the limited addition~~exemption~~ will equal the amount of emissions contained in the~~annual emissions~~ most recent emissions data report that has received a positive or qualified positive emissions data verification statement.
>
> (C) Beginning in 2013 on October 1 of each year the limited addition~~exemption~~ will be increased by the amount of emissions contained in the most recent emissions data report that has received a positive or qualified positive emissions data verified statement during that year.
>
> (D) If for any year ARB has assigned emissions to an entity in the absence of a positive or qualified positive emissions data verification statement the calculation of the limited addition~~exemption~~ will use the assigned emissions.
>
> (E) For the first compliance period all reported emissions or assigned emissions used to calculate the limited addition~~exemption~~ will include only the emissions associated with the scope for the program during the first compliance period.
>
> (F) Beginning in 2015, all reported emissions or assigned emissions used to calculate the limited addition~~exemption~~ will include the emissions associated with the change in scope taking place in 2015.

(G) On January 1, 2015, the limited addition~~exemption~~ will be increased by the amount of emissions included in the emissions data report received during 2014 but not yet included in the limited addition~~exemption~~ pursuant to section 95920(d)(2)(E).
(H) On December 31 of the calendar year following the end of a compliance period, the limited addition~~exemption~~ will be reduced by the sum of the entity's compliance obligation over that compliance period. (SCPPA6)

Response: We believe the term "limited exemption" is clearer than the change proposed in the comment. The intent of the provision is to exempt from the holding limit the allowances that covered entities need to comply with the regulation. The exemption would allow covered entities to face the same requirements as non-covered entities after they have accumulated enough allowances to meet their obligations. The exemption is not unlimited. It is limited by the entity's historic emissions. Calling the provision an "addition" would imply that we are providing covered entities with an extra benefit not afforded to non-covered entities, when all we are trying to do is ensure that market rules reflect the extra constraint faced by covered entities.

I-25. Comment: Section 95920(g) on corporate association holding limits should be clarified. ARB should clarify whether this limit applies to future allowances (purchased at advance auctions) as well as allowances for current and previous compliance periods. Holding limits are calculated separately for those categories, according to section 95920(c). Section 95920(g)(1) refers to a holding limit applying to compliance instruments, but all other provisions of this section 95920 (other than section (b)(3), which should also be amended) refer to limits on the holding of allowances, not compliance instruments in general. There is no reason to apply a holding limit to offsets as there is already a surrender limit on offsets. Section 95920(g)(2) refers to a limited exemption as defined in section 95920(f). However, section 95920(f) does not define a limited exemption (or addition). It appears that the reference should be to section 95920(d) instead. It is also unclear how the limited exemption (or addition) would apply to the amount provided in section 95920(g)(1). Will the limited exemption/addition for each entity be added to the group holding limit calculated under section 95920(g)(1)? This should be clarified.
Modify section 95920(g) as follows:

(g) Application of the Corporate Association Disclosure to the Holding Limit.

(1) The total number of ~~compliance instruments~~allowances held by a group of entities with a disclosable corporate association pursuant to section 95833 in their holding accounts must sum to less than the holding limit pursuant to section 95920(e), plus the sum of the limited additions specified in section 95920(g)(2).

(2) The limited addition~~exemption~~ for each entity which is part of a corporate association is the same as defined in section 95920(d~~f~~). (SCPPA6)

Response: We agree with the comment on the use of the term "compliance instruments" versus "allowances" in the holding limit, and made the change to section 95920(f) as suggested. (Please note that the section has been renumbered from 95920(g)(1) to 95920(f)(1).)

We do not agree with the suggested revision to 95920(f)(2), (formerly 95920(g)(2).) We believe that the term "limited exemption" is clearer than the change proposed in the comment. The intent of the provision is to exempt from the holding limit the allowances that covered entities need to comply with the regulation. The exemption would allow covered entities to face the same requirements as non-covered entities after they have accumulated enough allowances to meet their obligations. The exemption is not unlimited. It is limited by the entity's historic emissions. Calling the provision an "addition" would imply that we are providing covered entities with an extra benefit not afforded to non-covered entities, when all we are trying to do is ensure that market rules reflect the extra constraint faced by covered entities.

Transportation Sector Electrification

I-26. Comment: Perhaps the largest potential for emissions reductions in the state in the long-term lies in electrification of the transportation sector. However, these reductions are by no means assured given the high costs of infrastructure investment that the electricity sector and customers will need to make, as well as the costs of the vehicles themselves. Given these up-front cost-barriers, significant incentives will likely be needed to induce the early adoption of electric vehicles needed to establish a rapidly growing, vibrant electric transportation sector. SMUD strongly encourages the ARB to consider that the reduction in compliance need that will arise in the transportation sector as liquid fuel transportation emissions are shifted to the electric sector imply an increase in electric sector compliance obligation that is not currently covered in the sector allowance allocation structure laid out in the 15-day language. ARB should ensure that the increased emissions obligations that result from increasing electric transportation loads do not create a cost burden on utility ratepayers, in contradiction to the rationale for providing allowances to electrical distribution utilities. The amount of allowances added to the electric sector allocation should cover the potential increased compliance obligation associated with producing electricity for transportation loads. Of course, the cap and trade program in this aspect needs to be coordinated with the Low Carbon Fuel Standard program. LCFS credits are expected to provide a valuation of the difference between the emissions from electricity generation for transportation and the reduction in liquid fuel emissions, and this value is expected to be traded in the LCFS marketplace. This calculation "nets out" the increased electricity sector emissions, so the LCFS credit value does not reflect this increased obligation in the electricity sector. ARB should reflect the increased electricity sector emissions, and corresponding reduced transportation sector emissions, by adjusting the allowance allocations for the electric sector commensurate with the growth in electric transportation load. This load growth is different from any other load growth, as it corresponds to less energy use and dramatically fewer emissions in the transportation sector, and is the only load growth strongly supported by the State's energy and transportation policies and by the ARB's own climate policies. The additional electric sector allowances would be calculated each year based upon the previous year's measured load for electric transportation, multiplied by the default emission factor in the electric allocation spreadsheet or the default emission factor established for unspecified power in the cap and trade program. Modify section 95870 as follows:

> <u>(f) Increased Allocation to Electrical Distribution Utilities For Electric Transportation Growth. The Executive Officer will place an additional annual individual allocation in the appropriate accounts of each electrical distribution utility on July 15 of each calendar year from 2013-2020, calculated as the amount of measured electric transportation load in the previous year, as reported by each electrical distribution utility, multiplied by the default emissions factor.</u> (SMUD3)
>
> **Response**: We did not make this change. However, in accordance with Board Resolution 10-42, we will monitor electrification of the transportation sector and recommend regulation adjustments to the Board as appropriate.

Miscellaneous

I-27. Comment: ARB proposes an option for publicly owned utilities (POU) that would allow them to directly surrender allowances to meet compliance without monetizing them through the auction. LADWP strongly supports this provision as it recognizes that a vertically integrated POU that acts as both the electric distribution utility and the generator would otherwise have to sell allocated allowances at auction only to repurchase them to surrender for emissions associated with serving native load. LADWP is committed to working with ARB to further refine reporting protocols for the use of allowance value. (LADWP4)

> **Response**: Thank you for the support. No further response is required.

Imported Electricity

General and Support

I-28. Comment: PacifiCorp supports ARB's proposed methodology to allocate allowances based on the distribution utilities' projected compliance burden. Though PacifiCorp continues to have significant reservations regarding the use of State-and/or regional-based allowance trading regimes as the principal means of reducing carbon emissions, the Company strongly supports ARB's adherence to an emissions-based allowance allocation methodology, as opposed to a sales-based approach. (PACIFICOR3)

> **Response:** We thank PacifiCorp for support of the allowance allocation methodology.

I-29. Comment: NextEra urges ARB to consider the comments submitted by IEP and WPTF. Specifically the comments related to imported power, energy efficiency audits, resource shuffling, replacement power with respect to balancing authorities, and holding accounts. (NEXTERAENERGY2)

> **Response**: We acknowledge the comment. Please refer to our responses directed to the relevant comments submitted by parties noted by the commenter.

I-30. Comment: WPTF anticipates that linkage of the California Cap and Trade Program to an external emissions trading system within the WECC would necessitate changes to California's annual allowance budget to account for electricity imports from the linked jurisdiction. WPTF recommends that CARB explicitly provide for this eventuality in the regulation. (WPTF2)

> **Response:** We agree that linkage could change the accounting of emissions from imported electricity. If ARB links with another jurisdiction, GHG emissions associated with its electricity would face a compliance obligation in that jurisdiction, and the emissions from that electricity would no longer be considered part of California's emissions. While we have not explicitly stated how linking will be handled with respect to electricity imports within this regulation, those details will be addressed during future regulatory processes. This will include an allowance budget adjustment to reflect the emissions responsibility of each trading program. We do expect electricity utilities' long-term resource plans to incorporate California policies such as divestiture of GHG-intensive electricity from out-of-state coal generation.

I-31. Comment: The term "contract rights" should be clearly defined in the regulation. One criterion for claims of specified imports is that "the first deliverer must be the facility operator or have ownership or contract rights to electricity generated by the facility or unit claimed." The term "contract rights" is vague and provides no certainty regarding the type of commercial arrangements would qualify. Without further definition as to the type of arrangements that would qualify, the eligibility of contracts for a facility-specific emission rate would be subject to interpretation by verifiers. This is not acceptable. (WPTF2)

> **Response:** To address this concern, we modified the criterion for claims of specified imports in renumbered section 95852(b)(3)(B) to state that the electricity importer "must be the facility operator or have right of ownership or a written power contract, as defined in MRR section 95102(a), to the amount of electricity claimed…."

I-32. Comment: The proposed regulation does not make clear whether an out-of-state facility will have a cap-and-trade compliance obligation when its total emissions exceed 25,000 MT, but it imports only part of its capacity, and the import into California accounts for less than 25,000 MT of GHG emissions associated with the importer's total capacity. ARB should clarify that the importer's compliance obligation applies to emissions associated with delivery of power into California. Modify section 95812(c)(2)(b) as follows:

(b) Electricity importers of specified sources of electricity. The applicability threshold for an electricity importer from specified sources is based on the total annual emissions of the electricity generating facility from which the imported electricity originated. The applicability threshold for an electricity importer from a specified source which emits 25,000 metric tons or more of CO_2e per year is zero metric tons. (IEPA2)

Response: While we did not make the requested modification, we modified 95812(c)(2)(B) and added paragraphs 95812(c)(2)(b)(i and ii) to make it clear that any import from an electricity facility that has total emissions that exceed 25,000 $MTCO_2e$ has a compliance obligation.

I-33. Comment: Also modify section 95852(b)(7) as follows:

(7) The compliance obligation (CO_2e covered) is calculated based on the emissions from electricity deliveries into California from jurisdictions that are not approved for linkage pursuant to subarticle 12:

(A) Emissions which result from specified electricity deliveries (CO_2e specified) will be assigned the facility emission factor, determined by ARB, for electricity deliveries meeting the requirements of section 95852(b)(2) through (5);

1. Specified deliveries meeting the requirements of section 95852(b)(2);
2. The adjustment for replacement electricity associated with the variable renewable electricity pursuant to section 95852(b)(3);
3. The specified electricity meeting direct delivery requirements pursuant to section 95852(b)(4); and
4. The specified electricity generated from the use of biomethane which meets the requirements pursuant to section 95852.2. (IEPA2)

Response: Instead of modifying section 95852(b)(7), we deleted that section and added new section 95852(b)(1), which now defines the compliance obligations for first deliverers. New section 95852(b)(1)(B) provides an equation that represents the compliance obligation for electricity importers and clarifies the compliance obligation for electricity deliveries into California.

Asset-Owning Supplier

I-34. Comment: ARB has proposed modifying the definition of “asset controlling supplier” in both the MRR and Cap and Trade Rule (see sections 95102(a)(17) and 95802(a)(13)). The modifications would remove from the definition two retail providers in California, PacifiCorp and Sierra Pacific Power Company, leaving only one entity listed in the definition: the Bonneville Power Administration (“BPA”). It is not clear from the definition why these two entities no longer qualify as “asset-controlling suppliers,” and why BPA does still qualify as an “asset-controlling supplier.” Powerex requests that ARB clarify the criteria applied when determining whether an entity meets the definition of an “asset-controlling supplier,” as well as provide transparency with respect to the assessment of the “asset-controlling supplier” intensity factor and clarify the process by which an entity is granted or assigned status as an “asset-controlling supplier.”

By removing PacifiCorp and Sierra Pacific Power Company from the definition of “asset controlling supplier” in section 95102(a)(17) of the MRR and section 95802(a)(13) of the Cap and Trade Rule, the definition has been changed from including a list of example “asset controlling suppliers” to stating that BPA is an asset-controlling supplier. While Powerex interprets this statement to mean that BPA is just one example of an asset controlling supplier, it could be read to require a modification to the definition every time ARB wants to recognize another asset-controlling supplier. To avoid having to modify a rule if and when ARB recognizes additional asset-controlling suppliers, Powerex recommends removing the second sentences of MRR section 95102(a)(17) and Cap and Trade Rule section 95802(a)(13), or revising those sentences to read: “Bonneville Power Administration (“BPA”) is one entity recognized by ARB as an asset-controlling supplier.” (POWEREX)

> **Response:** PacifiCorp is a multi-jurisdictional retail provider and is subject to the specific provisions of the MRR for such entities, rather than to the specific provisions for asset-controlling suppliers. We note that Powerex may request that we determine that it is an asset-controlling supplier, if Powerex controls assets and reports on all assets providing the same information needed to determine the EF of such a supplier. However, this is primarily a reporting function and will be addressed in the MRR FSOR if Powerex has also submitted these comments in that rulemaking. We understand the commenter’s concern and we will continue to monitor regulatory developments and propose any changes as needed.

Imported Electricity

I-35. (multiple comments)
Comment: CARB’s July 25 Notice suggests that section 95852(b)(7) is needed to clarify the appropriate calculation for out-of-state resources. Since the calculation is already addressed in the MRR, NCPA suggests that CARB strike the detailed descriptions and reference rather to MRR section 95111(b)(5). Modify section 95852(b)(7) as follows:

(7) The compliance obligation for ~~(CO2e covered) is calculation based on the~~ emissions from electricity deliveries from jurisdictions that are not approved for linkage pursuant to subarticle 12 is calculated in accordance with MRR section 95111(b)(5).
~~(A) Emissions which result from specified electricity deliveries (CO2e specified) will be assigned the facility emission factor, determined by ARB, for electricity deliveries meeting the requirements of section 95852(b)(2) through (5);~~

~~1. Specified deliveries meeting the requirements of section 95852(b)(2);~~
~~2. The adjustment for replacement electricity associated with the variable renewable electricity pursuant to section 95852(b)(3);~~
~~3. The specified electricity meeting direct delivery requirements pursuant to section 95852(b)(4); and~~
~~4. The specified electricity generated from the use of biomethane which meets the requirements pursuant to section 95852.2.~~

~~(B) All deliveries of electricity not meeting the requirements of section 95852(b)(2) through (5) will have emissions calculated using the default emission factor for unspecified electricity pursuant to section 95111 of MRR (CO2e unspecified).~~
~~(C)Emissions resulting from qualified exports (CO2e qualified exports) will be subtracted from the compliance obligation pursuant to section 95852(b)(6).~~
~~Compliance Obligation in CO2ecovered =CO2especified+ CO2eunspecified - CO2equalified export~~ (NCPA3)

Comment: Section 95852(b)(7) determines the compliance obligation for electricity that is imported from unlinked jurisdictions. The section paraphrases the provisions of MRR section 95111(b)(5) but does not replicate those provisions. The use of paraphrases instead of the precise provisions of MRR section 95111(b)(5) could lead to confusion. Any summary paraphrasing is likely to be somewhat inaccurate. Instead of trying to paraphrase MRR section 95111(b)(5) in section 95852(b)(7), the section should be revised to refer to MRR section 95111(b)(5). Modify section 95852(b)(7) as follows:

(7) The compliance obligation for ~~(CO2e covered) is calculation based on the~~ emissions from electricity deliveries from jurisdictions that are not approved for linkage pursuant to subarticle 12 is calculated in accordance with MRR section 95111(b)(5).~~:~~

~~(A) Emissions which result from specified electricity deliveries (CO2e specified) will be assigned the facility emission factor, determined by ARB, for electricity deliveries meeting the requirements of section 95852(b)(2) through (5);~~

~~1. Specified deliveries meeting the requirements of section 95852(b)(2);~~

~~2. The adjustment for replacement electricity associated with the variable renewable electricity pursuant to section 95852(b)(3);~~

~~3. The specified electricity meeting direct delivery requirements pursuant to section 95852(b)(4); and~~

~~4. The specified electricity generated from the use of biomethane which meets the requirements pursuant to section 95852.2.~~

~~(B) All deliveries of electricity not meeting the requirements of section 95852(b)(2) through (5) will have emissions calculated using the default emission factor for unspecified electricity pursuant to section 95111 of MRR (CO2e unspecified).~~

~~(C) Emissions resulting from qualified exports (CO2e qualified exports) will be subtracted from the compliance obligation pursuant to section 95852(b)(6).~~

~~Compliance Obligation in CO2ecovered =CO2especified + CO2eunspecified - CO2equalified export~~ (SCPPA6)

Response: We agree with the need to clarify the compliance obligations for first deliverers of electricity, whether they are operators of an electricity generating facility in California or electricity importers. New section 95852(b)(1) now precisely states the compliance obligation and indicates which emissions are included and which emissions are not included. Those revisions allowed for the elimination of section 95852(b)(7) in its entirety. Although we did not make the exact changes suggested in the comment, we believe our modifications have met this concern. Furthermore, the modified language provides clear cross-references to the MRR as needed.

e-Tags and Title

I-36. (multiple comments)
Comment: Currently, the cap-and-trade definitions provide that the “electricity importer” is the purchasing and selling entity (“PSE”) on the physical path where the delivery point is in California. (95802(a)(84). However, instances may arise when the PSE on the e-tag does not correctly identify the entity that owns power as it crosses the State’s borders. E-tags were designed to address and track compliance with the Western Electricity Coordinating Council’s reliability standards, and do not necessarily track energy ownership. IEP seeks assurances that the entity with the compliance obligation is the entity that has title to the power as it crosses the state’s border. Currently, IEP is not aware of a single precise method or tool to reliably and definitively track the proper entity with title to the power as it is delivered across California’s political borders. It may be the case that this concern arises only in the context of transactions to the CAISO market delivered at out-of-state nodes. CARB should therefore work with the CAISO and stakeholders to identify the scope of potential transactions where this issue arises and develop an appropriate tool or methodology. (IEPA2)

Comment: PacifiCorp does not support the conclusion that the use of e-Tags proves ownership or identifies the importer of energy. E-Tags are tools designed to facilitate identification and communication of interchange transaction information between parties. E-Tags are not used to establish title to energy or transmission. Legal title to energy is established by parties through bilateral contracts. E-Tags are typically prepared by the purchaser as part of its performance of a contract, but it is not the mechanism through which parties intend to or establish or keep track of ownership or allocate risk of loss on change in title. California cannot legally impose a new legal standard of how title is transferred at electricity market delivery points outside of California, or what constitutes intent to create legal relations with respect to title transfer outside of California. In addition, e-Tag authorship and approval guidelines are driven by the NERC standards process, and there is currently no standard for the PSE field on the e-Tag to be monitored by approval entities for accuracy. Since there is also no process for correcting an errant PSE entry on a finalized tag (now used as proof of ownership), there is the possibility that the e-Tag may indeed not accurately represent the chain of title. While PacifiCorp understands the appeal of using a device like an e-Tag to track the ownership of an electric energy commodity when it passes the state boundary, it is an imprecise and inappropriate tool. A Balancing Authority could become subject to legal responsibilities simply because an e-Tag for a California purchaser identifies the Balancing Authority as the source on an e-Tag, even though the Balancing Authority had nothing to do with the creation of the e-Tag. The NERC e-Tag establishes the Balancing Authority, but does not identify the actual resource. PacifiCorp therefore recommends that ARB change the importer definition that states that NERC e-Tags identifies the title holder when power crosses the state border, and instead use the parties' contract to establish where title lies. (PACIFICOR3)

Comment: During ARB's July 15, 2011 Workshop, stakeholders noted potential Cap and Trade implementation issues that might arise due to differences between the CAISO's geographical footprint, which has delivery points that extend beyond the state's boundary and ARB's authority to impose compliance obligations. The Regulation proposes to establish an obligation on the party that holds title to electricity as it is imported across the state boundary, and PG&E supports this concept. The Regulation relies upon electricity "tags" to establish ownership or title. As stakeholders at the workshop noted, tags have historically served a different function than establishing ownership and also tags to some CAISO delivery points are still deliveries to points outside of California. Due to these concerns, PG&E urges ARB and CAISO to review both the Regulation and the CAISO's tariff to ensure that the proposed regulatory approach is accurate and could withstand potential legal challenges which would impede successful implementation of the program. (PGE4)

> **Response:** We worked with CAISO to review the regulation and CAISO's tariff to ensure the accuracy of the approach. First deliverers that import electricity are electricity importers. We modified and renumbered the definition of "electricity importer" (new section 958102(a)(87) to identify the importer as the PSE listed on the last segment of the e-Tag for electricity delivered between balancing authority areas, and to remove the reference to that entity's ownership or title to the

delivered electricity. This modification is discussed more fully in responses to second 15-day changes to the regulation.

With respect to PACIFICOR3's comment, we note that one of the purposes of e-Tags is to schedule delivery of electricity between balancing authority areas. The regulation places the compliance obligation on the first deliverer of electricity. For imported electricity, the e-Tag identifies the deliverer on each segment, and includes segments that begin outside of California and end in California. Therefore, we believe it is appropriate to use e-Tags to identify PSEs as first deliverers of imported electricity delivered between balancing authority areas, identified on the segment that crosses into California where the first point of receipt is outside California and the final point of delivery is inside California.

I-37. Comment: Consistent capitalization and the use of defined terms will more clearly define that the Cap and Trade policies are limited to electricity imported to serve California load. Revise the terms "Electricity importer", and "electricity importer" to be "Electricity Importer" throughout the regulations. Also, revise the terms "imported electricity" with "Imported electricity," and consider replacing "electricity" with "Electricity" throughout the Regulations. (VEA)

Response: We did not make the recommended revision. We understand that in other settings, such as the CAISO tariffs and operating rules, defined terms are capitalized. However, the regulation is clear, and defined terms need not be capitalized to have precisely defined meanings.

I-38. (multiple comments)
Comment: Powerex strongly encourages CARB to conduct a stakeholder workshop dedicated to the subject of imported electricity. Complex changes have been proposed under the 15-day rule modification process concerning resource shuffling, direct delivery of electricity, variable renewable resources, and replacement electricity. These changes will significantly alter the structure of reporting for electric power entities as well as the market for imported electricity. Such a workshop would enable ARB to clarify its intent with respect to the new concepts and for affected entities to provide further comments to help ensure that the programs function well. Since many of these issues are interwoven with both the Mandatory Reporting Rule and the Cap and Trade Rule, the workshop ideally would cover both rules as they address imported electricity. In view of the overall timing ARB's implementation of the AB 32 Scoping Plan, Powerex strongly encourages ARB to conduct such workshop as soon as possible, preferably prior to the release of the planned second package of 15-day rule modifications. (POWEREX)

Comment: LS Power encourages CAISO and CARB to conduct an open stakeholder process to discern a more appropriate mechanism to track title than e-tagging convention as it is applied to a sale into the CAISO market from out-of-state points of delivery. It is imperative that such an effort be open to public comment and the method that is eventually used not result in a unilateral alteration of commercial terms without the principle parties' consent. (LSPOWER)

> **Response:** We agree, and held a stakeholder workshop on August 26, 2011, prior to proposing the second 15-day changes to the regulation. In addition, CAISO staff participated in the Western Power Trading Forum meeting held on August 2, 2011, and explained that many electricity importers have not been using e-Tagging in accordance with the CAISO tariff. ARB staff participated as observers in that meeting. Please see our response to IEPA2 and PACIFICORP above regarding the issue of tracking title. We and CAISO are convinced that e-Tags are critical to tracking first deliveries of electricity into California. We have seen no evidence that our use of e-Tags to establish the identity of first deliverers would result in a "unilateral alteration of commercial terms."

I-39. Comment: The current definition of "electricity importers" in section 95802(a)(84), which assigns "electricity importer" status to a downstream purchaser within ARB's jurisdiction when the original purchasing-selling entity (PSE) is outside of ARB's regulatory authority could lead to unintended and unfair consequences and should be modified. Not only is the definition inconsistent with the fundamental principle that the Cap and Trade Regulation is source based, but it could also lead to California load being assessed GHG compliance costs twice for the same electricity imports. The electricity markets would be distorted and provide out-of-state importers with a financial windfall. Also, the California Independent Systems Operator (CAISO) has language in its Tariff that make it clear that sellers at out-of-state interties do indeed deliver the electricity into California. CAISO appears to believe that ARB would be able to rely on these provisions to conclude that the seller who imported electricity at an out-of-state point of delivery within CAISO is always the first deliverer in California. If so, the provision pushing the compliance obligation downstream in section 95802(a)(84) is unnecessary and should be deleted. Accordingly, ARB should revise its definition of electricity and reaffirm that it will consistently require the entity who imports the electricity into California to comply with the Cap and Trade program requirements, rather than the purchaser or recipient of that imported electricity. (SCE3)

> **Response:** We agree that the electricity importer is not a downstream purchaser. We modified the definition, now renumbered as section 95802(a)(87), by removing the last sentence.

I-40. Comment: Valley Electric requests that CARB explicitly recognize the intent to distinguish between load that sinks in the state of California versus that which does not by indicating that further information may be necessary. Modify sections 95802(a)(84) and 95802(a)(131) as follows:

> (84) "Electricity Importers" are marketers and retail providers that hold title to imported electricity. For electricity delivered between balancing authority areas, the entity that holds title to delivered electricity is identified on the NERC E-tag as the purchasing-selling entity (PSE) on the tag's physical path, with the point of

receipt located outside the state of California, and the point of delivery (as specified within the e-tag or through additional information as needed) located inside the state of California. Federal and state agencies are subject to the regulatory authority of ARB under this article, and include Western Area Power Administration (WAPA), Bonneville Power Administration (BPA) and California Department of Water Resources (DWR). When PSEs are not subject to the regulatory authority of ARB, the electricity importer is the immediate downstream purchaser or recipient that is subject to the regulatory authority of ARB.

(131) "Imported electricity" means electricity generated outside the state of California and delivered to serve load inside of California. Imported electricity includes electricity delivered from a point of receipt located outside the state of California, to the first point of delivery inside the state of California, having a final point of delivery in the state of California. Imported electricity includes electricity imported into the state of California over a multi-jurisdictional retail provider's transmission and distribution system, or electricity imported into California over a balancing authority's transmission and distribution system. Imported electricity includes electricity that is a result of cogeneration outside of California. Imported electricity does not include electricity wheeled through California, which is electricity that is delivered into the state of California with final point of delivery outside the state of California. (VEA)

Response: Although we did not make the specific modifications that Valley Electric suggests, we worked with Valley Electric and made other modifications to the two definitions in order to clearly distinguish between electricity serving load in California and electricity that Valley Electricity schedules into the CAISO market but uses to serve load outside of California. Valley Electric has confirmed to staff that their concern has been addressed.

I-41. (multiple comments)
Comment: Amend the definition for "Electricity Importer" so that it does not rely in all cases on the E-tag to designate ownership of the electricity at the time it crosses the California border when the transaction is a sale to a CAISO market (as opposed to a bilateral arrangement). Modify section 95802(a)(84) as follows:

"Electricity Importers" are marketers and retail providers that hold title to imported electricity. For electricity delivered between balancing authority areas, the entity that holds title to delivered electricity ~~is~~ may be identified on the NERC E-tag as the purchasing-selling entity (PSE) on the tag's physical path, with the point of receipt located outside the state of California, and the point of delivery located inside the state of California. Federal and state agencies are subject to the regulatory authority of ARB under this article, and include Western Area Power Administration (WAPA), Bonneville Power Administration (BPA) and California Department of Water Resources (DWR). When PSEs are not subject to the regulatory authority of ARB, including tribal nations, the electricity importer is the

> immediate downstream purchaser or recipient that is subject to the regulatory authority of ARB. (IEPA2)

Comment: CARB's reliance on e-tags as conclusive evidence of ownership to power as it crosses the California border within the proposed regulations definition of electricity importer is problematic. Under the proposed Cap and Trade Regulation, CARB will use e-tags for a purpose for which they were never designed. Imputing a legal ownership presumption to e-tags will place new uses and requirements that were not contemplated when the e-tagging concept was originally developed for reliability reasons. In addition, there will be instances when CARB misrepresents the nature of the property rights and associated liabilities (such as risk of loss) transferred at the delivery point through the commercial transaction. The result is that CARB may improperly assign a cap-and-trade compliance obligation to an entity that is not subject to California state jurisdiction because it did not own the power when it crossed the State border. This defect creates a risk of potential legal challenge on an interstate commerce clause claim. Avoiding this risk is necessary to provide certainty for regulated entities and credibility for the Cap and Trade market. To avoid these concerns, LS Power recommends that CARB amend the definition for "Electricity Importer" (section 95802(a)(84)), so that the definition does not rely on the e-tag to designate ownership of the electricity. LS Power is not aware of another approach that would definitively track the entity with title when the power crosses the State's political borders. Modify section 95802(a)(84) as follows:

> (84) "Electricity Importers" are marketers and retail providers that hold title to imported electricity. For electricity delivered between balancing authority areas, the entity that holds title to delivered electricity ~~is identified on the NERC E-tag as the purchasing-selling entity (PSE)~~ on the tag's physical path, with the point of receipt located outside the state of California, and the point of delivery located inside the state of California. Federal and state agencies are subject to the regulatory authority of ARB under this article, and include Western Area Power Administration (WAPA), Bonneville Power Administration (BPA) and California Department of Water Resources (DWR). When PSEs are not subject to the regulatory authority of ARB, including tribal nations, the electricity importer is the immediate downstream purchaser or recipient that is subject to the regulatory authority of ARB. (LSPOWER)

Comment: The sink-identifying information on e-tags may not distinguish between points of delivery within the CAISO BAA that are in or outside of California. Traditionally, e-tags used for energy deliveries to the CAISO have simply specified "CAISO" as the point of delivery. Without a further specification of the location of the energy deliveries, it will not be possible to implement the rules as stated in the July proposal. The e-tags used in the CAISO scheduling processes must be able to identify delivery points more specifically than simply "CAISO." E-tag points of delivery such as "CAISO – Valley NV" could provide the necessary specificity. Also, E-tags that specify only CAISO as a delivery point would have to be conjoined with other entity information that could be used to determine the quantity of electricity that was imported into the

CAISO for non-California load. For example, metering information collected by the CAISO could serve this purpose. (VEA)

Response: As discussed above, we modified the definition of PSE to remove the reference to title, because this regulation applies to first deliverers. We also modified requirements in section 95852(b) to clarify that ownership or contracts are also needed to clarify ownership of electricity generated at a specified source, or delivered from unspecified sources. We do not rely solely on e-Tags to provide evidence of ownership, contractual relationship, or delivery.

With respect to VEA's contention, the traditional designation of CAISO as the point of delivery is incorrect, and not compliant with the CAISO tariff, as explained by CAISO to stakeholders in several public meetings. E-Tags used in the CAISO system must identify a sink in California, except in extremely limited circumstances (e.g., when CAISO must procure emergence power for reliability).

I-42. Comment: In several locations in the MRR and in the Cap and Trade Regulations, the NERC E-Tag is identified as the element that will determine title to the power imported, and thus assigns the responsibility for any GHG liability that may accrue from that importation. This is an incorrect application of the E-Tag. Title is a matter of contract law, not a function of a reliability tool designed to track power transactions between BAAs. Moreover, CARB's definition of "PSE" is "the functional entity that purchases or sells, and takes title to, energy, capacity and reliability-related services." These are distinct product markets. An entity can contract for, and take title to, one or more of these products without taking title to all three. It is important to recognize that both CPUC and CEC rely upon E-Tags to audit RPS transactions, and to verify that WREGIS certificates are associated with imports by entities subject to RPS requirements over the appropriate time interval. This is a far different use of an E-Tag than its proposed use to determine title to power, and the presumption of responsibility for GHG liability. CARB should abandon the proposed use of e-tags as a proxy for assigning title to import transactions. (NAES)

Response: We modified the definition of "PSE" (now section 95802(a)(224)) removing the reference to title. The definition of PSE quoted above is that contained in NAESB Wholesale Electric Quadrant Electronic Tagging - Functional Specifications, Version 1.8.1. It was approved by the WEQ EC on October 27, 2009, and applies to electricity delivered between balancing areas throughout the United States. As discussed in the response to Comment I-36, we continue to use e-Tags to identify the first deliverer of electricity imported into California.

I-43. Comment: The use of e-Tags for identification of ownership may not be sufficient for all transactions. CARB's proposal to use the e-Tag as the evidence of ownership and title transfer may not work. There exist numerous injections points into the State of California, each with different physical and contractual elements. Seeking to use e-Tags as a standardized approach for identification of the entity that owns the energy when it crosses the California border is especially problematic for certain transactions where the title transfer location is a node outside of California. Potential inaccuracies may result from standard utilization of the e-Tag for designation of ownership. For example, deliveries at the California Oregon Border. The Southern Intertie segment, or the California Oregon Border (COB), consists of three 500 kV AC lines from the John Day Substation to COB. Deliveries to COB all commence with transmission title on the Southern Intertie with a Point of Receipt of John Day and a Point of Delivery to either Malin or Captain Jack. With Malin and Captain Jack residing in the state of Oregon and being a market-recognized trading hub for Northwest deliveries into California, this is the location at which title of energy transfers to the Purchase and Selling Entities (PSE) continuing deliveries to California. In this transaction, the e-Tag accurately identifies the entity who has title of the energy when is crosses the California border. Another inaccuracy may result from use of the e-Tag for designation of owners for deliveries at the Nevada Oregon Border. The Nevada Oregon Border (NOB) transmission segment is comprised of major transmission facilities consisting of a 1000 kV DC line between Celilo Substation and the Oregon-Nevada border. Deliveries to the Nevada Oregon Border all commence with transmission with a Point of Receipt of Big Eddy and a Point of Delivery to Sylmar. Unlike COB, NOB is a contractually defined geographical point in which the Bonneville Power Administration and the California ISO change ownership and is also considered the Point of Receipt in which the CAISO takes title of the energy. In this transaction, the e-Tag may not properly identify the entity with ownership of the energy at the time it crosses the California border. (IBERDROLA)

> **Response:** We modified this provision to remove the reference to title in the definition of “electricity importer”. We discuss this modification, including clarification regarding our use of e-Tags, more fully in responses to second 15-day changes.

I-44. Comment: Legal certainty is needed on who holds responsibility for electricity imports. WPTF is aware of concerns that have been raised about the ability of CARB to hold entities legally responsible for deliveries to the CAISO through interties outside the state boundary. Nevertheless, WPTF believes that holding the entity that bids and schedules power into California responsible for the carbon associated with these imports is the correct policy approach. This approach will ensure that the entity that receives payment for power delivery into California, and the carbon premium imbedded in the power price, will also have the carbon obligation for the associated emissions. This aligns the carbon obligation with the entity best able to control imported emissions and ensures equal treatment of all importers. The alternative that some stakeholders appear to be advocating is for the CAISO to determine the emissions associated with electricity delivered to external interties, acquire and retire allowances to cover these emissions, and to somehow pass these costs to load. Not only would this alternative be substantially more complicated to implement, but it would create a loophole where imports to California via CAISO external interties would receive a premium for carbon, because it will be reflected in California power prices, but no associated carbon obligation. This would be unfair to other importers, and create an incentive for imports through those points. For these reasons, WPTF opposes an outcome that would require the CAISO being held responsible for carbon. WPTF understands the legal considerations with respect to imports, and is not in a position to conduct a full legal analysis, other than to note that it is in the interest of all capped entities for the regulations with respect to imports to apply to all imports in a similar manner, and to avoid regulations that will provide perverse scheduling incentives. We support CARB's effort to work with the CAISO and the Department of Justice to develop the most legally and technically sound basis, consistent with the CAISO tariff, for an approach that holds the bidding/scheduling entity responsible for imports via the external interties. (WPTF2)

> **Response:** We appreciate WPTF's support of our approach, and agree that it will best provide equal treatment to all importers.

I-45. Comment: Section 95852(b) provides for the calculation of the compliance burden of first deliverers of electricity. The opening provision in the section should be revised as follows to make it clear that the compliance obligation will be calculated in accordance with all of the paragraphs of section 95852(b), not just the first paragraph. Modify section 95852(b) as follows:

> (b) First Deliverers of Electricity. A first deliverer of electricity covered under sections 95811(b) and 95812(c)(2) has a compliance obligation for every metric ton of CO_2e of emissions, subject to section<u>s</u> 95852(b)(1) <u>to (b)(7) inclusive</u>, from a source in California or in a jurisdiction where a GHG emissions trading system has not been approved for linkage by the Board pursuant to subarticle 12. And, where the thresholds set out in section 95812 have been reached and for which a positive or qualified positive emissions data verification statement is issued or there are assigned emissions. (SCPPA6)

> **Response:** We modified and renumbered section 95852(b), in part to provide more clarity about the calculation of the compliance obligation of first deliverers. We did not make the modification requested, but we met the concern by adding new section 95852(b)(1) to clarify compliance obligations. The new section clearly defines the obligation for first deliverers that are operators of electricity-generating facilities in California, and provides an equation that precisely describes the compliance obligation for first deliverers that are electricity importers.

I-46. Comment: It appears that section 95852(b) paraphrases the MRR sections that cover reported emissions from specified imported electricity. LADWP recommends clarifying the cross references to the MRR, including general requirements in section 95111(a)(4), calculations for specified facilities in section 95111(b)(2), and requirements for claims to specified sources of imported electricity and associated emissions in section 95111(g). LADWP recommends that subparagraph (D) be deleted since the MRR requires reporting of all fuel types under section 95111(g)(1)(L).

With regard to managing renewable resource imbalance, the CPUC and CEC are currently vetting how best to account for renewable resources, including the scenario when a resource produces more renewable energy than originally anticipated or scheduled. It appears that subparagraph (D) could be interpreted to preclude EDUs from receiving the emissions benefits associated with over-generation received from a renewable resource. This approach is incorrect insofar as the over-generation of a zero emitting specified renewable resource would still displace emitting fossil fuel generation, thereby avoiding GHG emissions. Under these circumstances, the quantity of non-emitting electricity delivered could exceed the amount under ownership or specified in a contract, and should not be assigned GHG emission penalties. Modify section 95852 (b)(2) as follows:

> (2) The following criteria must be met for <u>first deliverers for imported electricity from specified sources:</u> ~~electricity deliveries to calculate their compliance obligations based on an ARB facility-specific emission factor specified pursuant to MRR section 95111 less than-the-default emission factor for unspecified electricity specified pursuant to MMR section 95111:~~
>
> > (A) Electricity deliveries must <u>meet the requirements of</u> ~~be reported to ARB pursuant to~~ MRR section 95111(a)(4);
> > (B) <u>Claims for specified imported electricity must be calculated pursuant to MRR section 95111(b) and meet the requirements in MRR section 95111(g)</u> ~~The first deliverer must be the facility operator or have ownership or contract rights to electricity generated by the facility or unit claimed;~~
> > (C) First deliverers must report electricity from specified sources to ARB using the ARB specified source identification number assigned to the source pursuant to MRR; and
> > ~~(D) If there are other parties within the contract chain of custody, then the original source of generation and quantity of MWhs to be delivered under the original contract-must be identified within the entire contract chain. The quantity of electricity delivered, and for which an ARB facility-specific emission factor specified-pursuant to MRR section 95111 is claimed, cannot exceed the original amount under ownership or contract rights reported pursuant to section 95852(b)(2)(A).~~ (LADWP4)

Response: We agree that changes were needed to clarify the treatment of specified imported electricity. We modified new section 95852(b)(3) (previously paragraph (b)(2)) to more clearly state the requirements for claims for a compliance obligation for delivered electricity based on a specified source emission factor lower than the default emission factor. We no longer use specific references to several parts of MRR section 95111. The MRR's treatment of the reporting of electricity from specified sources is covered in sections 95111(a),(b),(c), and (g). We deleted old subparagraph 95852(2)(D) as requested. We did not make the exact changes suggested in the comment, but we believe our modifications have met the concerns noted.

As explained in the renewable electricity section of this FSOR, it is important that electricity importers have ownership or contract rights to procure electricity from a renewable resource if such electricity is allowed to be used in the calculation of the RPS adjustment pursuant to new section 95852(b)(4). If a first deliverer has such rights, it is not necessary that they always apply to a specific quantity of generated RPS electricity. Other information used in verification for the MRR ensures that only RPS electricity can be used to calculate the new RPS adjustment in modified section 95852(b)(4). These modifications to the treatment of renewable electricity should satisfy the commenter's concern regarding over-generation.

I-47. Comment: Section 95852(b)(2) contains criteria that must be met by importers who want to calculate their compliance obligation using facility-specific emission factor rather than the default emission factor. The section should be revised to make it clear rather than implied that the criteria apply to imports from a jurisdiction that is not linked to the California cap-and-trade program. Also, section 95852(b)(2)(D) should be revised to eliminate the requirement that when there is a chain of custody for the electricity from the specified source the importer must identify the amount that was to be delivered under the original contract with the facility. It would be difficult if not impossible for the importer to know the original *amount* in a complex chain of contracts unless the importer were a party to the original contract. Modify section 95852(b)(2) as follows:

(2) The following criteria must be met for first deliverers of electricity generated outside California in jurisdictions where a GHG emissions trading system has not been approved for linkage by the Board pursuant to subarticle 12~~deliveries~~ to calculate their compliance obligations based on an ARB facility specific emission factor specified pursuant to MRR section 95111 less than the default emission factor for unspecified electricity specified pursuant to MRR section 95111:

(A) Electricity deliveries must be reported to ARB pursuant to MRR section 95111;

(B) The first deliverer must be the facility operator or have ownership or contract rights to electricity generated by the facility or unit claimed;

(C) First deliverers must report electricity from specified sources to ARB using the ARB specified source identification number assigned to the source pursuant to MRR; and

(D) If there are other parties within the contract chain of custody, then the original source of generation~~ and quantity of MWhs to be delivered under the original contract~~ must be identified within the entire contract chain. The quantity of electricity delivered, and for which an ARB facility specific emission factor specified pursuant to MRR section 95111 is claimed, cannot exceed the ~~original~~ amount under ownership or contract rights reported pursuant to section 95852(b)(2)(A). (SCPPA6)

Response: We agree and made modifications to section 95852(b) based on stakeholder input to make it clear that the criteria used to calculate the compliance obligation using facility-specific emission factor rather than the default emission factor applies to electricity from a source in California or in a jurisdiction where a GHG emissions trading system has not been approved for linkage by the Board. Due to the extensive modifications that have been made, we did not make the exact changes suggested in the comment, nor do they appear in the same subsection; however, we believe our modifications have met the concerns noted by the commenter.

Also, we agree with the comment suggesting the elimination of the requirement that when there is a chain of custody for the electricity from the specified source the importer must identify the amount that was to be delivered under the original contract with the facility contained in section 95852(b)(2(D). That language has been eliminated.

Qualified Exports

I-48. Comment: SCE supports the treatment of qualified exports in sections 95802(218), 95852(b)(6), and 95852(b)(7), as it accurately addresses the complexities of electricity contracting and trading structures where power can be separately imported and exported within an hour. For compliance entities that must deal in these complex markets, this treatment of qualified exports will help to maintain fungible and efficient electricity markets and avoid undue compliance costs. SCE supports the one-hour time slot for netting qualified exports with imports, as it aligns well with current energy scheduling and marketing practices. (SCE3)

Response: Thank you for the comment. We appreciate the support.

I-49. Comment: ARB has not determined how compliance entities will be able to allocate their total qualified exports to their imports. Such allocation is important if a compliance entity will have imports in any given hour that have originated from a variety of specified and unspecified sources with different emissions factors. ARB should clarify how the emissions burden of qualified exports will be calculated. In section 95852(b)(7), this emissions burden is subtracted from specified and unspecified imports. However, ARB does not appear to have articulated how emissions for qualified exports will be calculated. ARB should be aware that the emissions rate for exports is often unknown. Exports, for purposes of this rule, will likely be sourced or purchased in California, but the specific source may be unknown. Current E-tag practices for exports often list a generic power source, such as “SP 15 System.” ARB has not stipulated what emissions rate should be used for this or other generic system power. Without an understanding of the emissions rate for system-sourced power exported from California, the qualified exports rule cannot be applied.

To address this situation, ARB needs to determine what emissions rate(s) it will use for qualified exports from unspecified sources. SCE believes that using a single “qualified export emissions rate" for all exports originating from California will lead to unintended consequences, including gaming opportunities and market changing behavior, especially if there is a difference between the default emissions factors for imports and exports. SCE suggests that ARB develop rules similar to those for default imports, such that unspecified exports that sink in BPA balancing authority receive an emissions rate of 0.0856 metric tons per MWh, while exports to other balancing authorities should receive an emissions rate of 0.428 metric tons per MWh. However, ARB should not use the intertie location as a proxy for the final power sink, as power that passes through a specific intertie does not necessarily sink in that region. In addition, ARB has not determined how compliance entities will be able to allocate their total qualified exports to their imports. Once again, such allocation is important if a compliance entity will have imports in any given hour that have originated from a variety of specified and unspecified sources with different emissions factors. In part due to the complexity of this issue, SCE recommends (as noted above) that ARB should take steps to analyze and model the implications of GHG regulations on power markets and power flows. Thorough modeling is necessary to inform ARB and other stakeholders what the impact ARB's cap-and-trade program could have on the power markets and WECC-wide power flows, and to help ARB preserve a functioning, efficient, and secure market. (SCE3)

Response: The commenter requests clarification on how qualified exports will be calculated. We modified section 95852(b)(5) to clarify the calculation of the new QE adjustment equivalent to the quantity, in MWh, of qualified exports, multiplied by an emission factor as specified. We agree that the emissions rate for exports may be unknown; in these cases, the default emission factor must be used, because the exporter cannot claim the export as originating at a specified source. We agreed that using a single emission factor ("rate") for qualified exports would not be appropriate. Under our new approach, during any hour for which an electricity importer claims qualified exports, the QE adjustment (which is a negative term in the compliance obligation equation) is calculated as the lower of the quantities of exports or imports, multiplied by the lowest emission factor of any export or import during the hour. For example, if an electricity importer imported 10 MWh of electricity with an emission factor of one $MTCO_2e$ per MWh, and exported 5 MWh of unspecified electricity (EF of 0.428), the QE adjustment would be five times 0.428, or 2.14 $MTCO_2e$.

We do not agree that the emission factor for qualified exports should depend on where the power is consumed ("sinks"). We believe that our approach will apply the proper emission factor (EF), and limit the potential for leakage. Because this and other imported electricity issues are complex, we plan to continue monitoring, analyzing, and modeling the effects of the regulation on the power market. If in the future we observe gaming or leakage, we will consider amending the regulation if necessary.

I-50. Comment: NERC E-tags are used only when electricity crosses between Balancing Authorities, which is not always aligned with imports and exports across the physical California border. LADWP recommends that the documentation requirement for NERC E-tags be stricken from this definition as verification can be handled through other types of documentation, such as contracts and settlement data. Additionally, it is unclear under the Mandatory Reporting Regulation (MRR) whether qualified exports are calculated hourly or annually. LADWP is concerned that reconciliation on an hourly basis for 8,760 hours in a calendar year will be administratively burdensome for the covered entity and the verification body. Modify section 95802(a)(218) as follows:

> (218) "Qualified Export" means emissions associated with electricity that is exported in the same hour as imported electricity and ~~documented by NERC E-tags~~. Only electricity exported within the same hour and by the same PSE as the imported electricity is a qualified export. It is not necessary for the imported and exported electricity to enter or leave California at the same intertie. ~~Emissions associated with qualified exports may be subtracted from the associated imports. Qualified exports shall not result in a negative compliance obligation for any hour.~~ (LADWP4)
>
> **Response:** We agree that e-Tags are required only for electricity crossing between balancing authorities. However, our definition of electricity importer, and our changes to section 95852(b), including references to the MRR, make it clear that other data, including contracts and settlement data, may be used as part of the documentation for imported electricity. After working closely with CAISO and with many stakeholders, we remain convinced that the e-Tag approach is best for designating the first deliverer when e-Tags are required, as they are for electricity that crosses between balancing authority areas.
>
> Based on these comments, and further discussion with CAISO and other stakeholders, we modified and renumbered the treatment of qualified exports as new section 95852(b)(5). We now include a QE (qualified exports) adjustment in the equation defining an electricity importer's compliance obligation. While we did not follow LADWP's suggestion for what EF to use for qualified exports, we did clarify how we modified the EF requirement for the QE adjustment. The EF that must be applied to qualified exports to calculate the QE adjustment is the lowest emission factor for any portion of the electricity claimed as either qualified exports, or the corresponding imports, during the hour in question. Therefore, we do not use a single QE emissions rate for all exports, and we believe that our approach will not lead to unintended consequences. New language in section 95852(b)(5) makes it clear how qualified exports are allocated against corresponding imports on an hourly basis, and the compliance obligation equation shows how the QE adjustment is made on an annual basis.

I-51. Comment: As currently written, section 95852(b) would seem to create a compliance obligation for emissions from all sources in linked jurisdictions, rather than emissions associated with imports from these sources. Modify section 95852(b) as follows:

(b) First Deliverers of Electricity. A first deliverer of electricity covered under sections 95811(b) and 95812(c)(2) has a compliance obligation for emissions, ~~subject to section 95852(b)(1)~~, from a source in California ~~or~~ and, subject to section 95852(b)(1), emissions associated with electricity imported into California from a jurisdiction where a GHG emissions trading system has not been approved for linkage by the Board pursuant to subarticle 12. And, where the thresholds set out in section 95812 have been reached and for which a positive or qualified positive emissions data verification statement is issued or there are assigned emissions. (WPTF2)

Response: We modified section 95852(b), including adding new section 95852(b)(1), which provides an equation for the calculation of the full compliance obligation for an electricity importer. The compliance obligation applies to first deliverers only for electricity that they deliver to California. The compliance obligation includes imported electricity reported pursuant to the MRR, and not emissions from all sources in linked jurisdictions, because first deliverers only report emissions for imports that they deliver to California.

I-52. Comment: A first deliverer's compliance obligation is for a subset of emissions that are reported and included in a positive or qualified positive verification statement. We recommend that section 95852(b) be modified to clarify that the compliance obligation is based on covered emissions identified in the MRR that carry a compliance obligation. LADWP also proposes that references to the resource shuffling provision be removed until further vetting. It appears that sections 95852(b)(2) through (7) are intended to clarify compliance obligations for first deliverers of electricity. LADWP recommends that these subsections be further clarified and aligned with the MRR. The MRR section 95111 includes several formulas for quantifying various types of emissions, but it appears there is no single "grand total" that can be pointed to in the MRR for first deliverers. It would be helpful for ARB to establish a clear cross reference from this Regulation to the emissions calculated in MRR that carry a compliance obligation. Modify section 95852(b) as follows:

(b) First Deliverers of Electricity. A first deliverer of electricity covered under sections 95811(b) and 95812(c)(2) has a compliance obligation for every metric ton of covered CO_2e emissions as calculated in Section 95111(b)(5) of MRR. ~~Subject to section 95852(b)(1) from a source in California or in a jurisdiction where a GHG emissions trading system has not been approved for linkage by the Board pursuant to subarticle 12.~~ And, where the thresholds set out in section 95812 have been reached and for which a positive or qualified positive emissions data verification statement is issued or there are assigned emissions. (LADWP4)

Response: We agree with the need to clarify this language, and made significant modifications to section 95852(b) to clarify the compliance obligations for first deliverers of electricity that are operators of an electricity generating facility in California and for electricity importers. New section 95852(b)(1) now precisely states the compliance obligations and indicates which emissions are included and which emissions are not included. The equation in that section clearly shows what reported emissions associated with imported electricity are included or excluded from the full compliance obligation. Although we did not make the exact changes suggested in the comment, we believe our modifications have met this concern. In addition, while we do not believe that the resource shuffling provision should be removed, we did make modifications recommended by the commenter and other stakeholders, and we held a technical workshop that included discussion of resource shuffling.

I-53. Comment: Section 95852(b) should reference not only subsection (b)(1), but subsections (b)(2) through (7) as well, as each of these subsections qualifies the calculation of the compliance obligation by referencing emissions that are not actually included. Modify section 95852(b) as follows:

(b) First Deliverers of Electricity. A first deliverer of electricity covered under sections 95811(b) and 95812(c)(2) has a compliance obligation for every metric ton of CO_2e of emissions, subject to section<u>s</u> 95852(b)(1) to <u>(b)(7) inclusive</u>, from a source in California or in a jurisdiction where a GHG emissions trading system has not been approved for linkage by the Board pursuant to subarticle 12. And, where the thresholds set out in section 95812 have been reached and for which a positive or qualified positive emissions data verification statement is issued or there are assigned emissions. (NCPA3)

Response: We agree that the regulation should more clearly state the calculation of compliance obligations, and we made significant modifications to section 95852(b) based on stakeholder input, to clarify the compliance obligations for first deliverers of electricity that are operators of an electricity generating facility in California and for electricity importers. New section 95852(b)(1) now precisely states the compliance obligations and indicates which emissions are included and which emissions are not included. The equation in the section calculates the "grand total" compliance obligation for an electricity importer. Although we did not use the exact language suggested in the comment, we believe our modifications have addressed the concern noted.

Direct Deliverer of Electricity

I-54. (multiple comments)
Comment: The definition of "direct delivery" should be as close as possible to the definition of category 1 resources in the recently passed RPS bill - SBX1 2. Modify section 95802(a)(68) as follows:
(68) "Direct Delivery of Electricity" means electricity that meets any of the following criteria:
(A) The facility has a first point of interconnection with a California balancing authority;
(B) The facility has a first point of interconnection with distribution facilities used to serve end users within a California balancing authority area;

(C) The electricity is scheduled for delivery from the specified source into a California balancing authority without replacement electricity from another source, except for that needed for hourly or interhourly balancing requirements; or
(D) There is an agreement to dynamically transfer electricity from the facility to a California balancing authority. (SMUD3)

Comment: The CPUC and CEC have commenced regulatory proceedings for the implementation of the 33 percent RPS as authorized under SBX1 2. In these proceedings, stakeholders are vetting the details for various definitions, including what does or does not constitute "direct delivery" of electricity. It would be appropriate for ARB to reference the CPUC and CEC as the entities that will ultimately establish the criteria for what constitutes "direct delivery of electricity" to ensure that treatment is consistent with the regulations that will implement SBX1 2. Modify section 95802(a)(68) as follows:

> (68) "Direct Delivery of Electricity" means electricity that meets Public Utility Code Sections 399.16(b)(1)(A) and 399.16(b)(1)(B) as interpreted by the California Public Utilities, Commission, and the California Energy Commission ~~any of the following criteria:~~
> ~~(A)The facility has a first point of interconnection with a California balancing authority;~~
> ~~(B) The facility has a first point of interconnection with distribution facilities used to serve end users within a California balancing authority area;~~
> ~~(C) The electricity is scheduled for delivery from the specified source into a California balancing authority without replacement electricity from another source; or~~
> ~~(D) There is an agreement to dynamically transfer electricity from the facility to a California balancing authority.~~ (LADWP4)

Response: The point of the modification recommended in the first comment above is to include what is often referred to as "firming and shaping" electricity to qualify as direct delivery when the electricity is "replacement electricity." By "category 1" the commenter is referring to section 399.16(b)(1)(A) of the Public Utilities Code. The recommended modification would not be the same as the PUC requirement for "category 1" electricity to qualify for the RPS; in fact, such electricity would not qualify for the RPS. However, we deleted the definition of "replacement electricity." We also modified the definition of "direct delivery of electricity" to refer to the MRR definition, in which the reference to replacement electricity is deleted. We also modified our approach to the treatment of RPS-eligible imported electricity such that replacement electricity is not required in order for RPS-eligible electricity to reduce the compliance obligation of a first deliver.

This regulation precedes the CPUC and CEC proceedings that will consider what kinds of delivery may or may not be needed for the RPS. We cannot refer to unknown future regulations. Furthermore, it is not clear that CPUC and CEC will define direct delivery; and if they do, it may not be the appropriate definition for use in this regulation.

Biomethane Section 95852(b)(5)

I-55. Comment: CCSF supports section 95852.2 establishing that there is no compliance obligation for CO_2 combustion emissions from high methane content biogas. According to the US EPA, methane is over 20 times more effective in trapping heat in the atmosphere than CO_2. Given the higher potency of methane in global warming effect and its higher short-term impact on climate change, CCSF urges ARB to include additional incentives to expand renewable electricity generation through biogas-fueled combined heat and power systems instead of the flaring digester gas. These incentives might include “first-in-line” benefits, the streamlining of offset protocols, more generous quantitative usage limits, or other mechanisms that would increase biogas capture from a variety of sources (e.g. wastewater treatment, agricultural activities, municipal compost facilities, and natural gas systems). The right incentives could spur the development of new methane/biogas capture technologies which have the greatest pound-for-pound impact on reducing the extent and pace of global climate change. (SFMAYOR3)

> **Response:** This comment does not pertain to the regulation, except in support of section 95852.2. We agree that the expansion of electricity generation using biogas should be encouraged, and if verified according to the provisions in this regulation, biogas is incentivized. However, the regulation is primarily designed to cap GHG emissions that do have a compliance obligation. Other state programs offer incentives for renewable electricity, including electricity from biogas consumption.

I-56. (multiple comments)
Comment: SMUD points out that sections 95852(b)(5) and 95852(b)(7)(a)(4) refer to Section 95852.2, while the correct reference should be 95852.1.1. Modify sections 95852(b)(5) and 95852(b)(7)(a)(4) as follows:

(5) Electricity generated from use of biomethane must comply with section <u>95852.1.1</u>~~95852.2~~, and must meet verification requirements for use of biomethane pursuant to MRR.
(4) The specified electricity generated from the use of biomethane which meets the requirements pursuant to section <u>95852.1.1</u>~~95852.2~~. (SMUD3)

Comment: Section 95852 sets out how each covered entity’s compliance obligations will be determined. It is important to clearly address liability relating to biomass-derived fuels. This section should clarify that, if the biomass-derived fuels meet the specified conditions, there is no compliance obligation for CO_2 emissions from the combustion of those fuels. Section 95852(b)(5) refers only to biomethane, but the more general term “biomass-derived fuel” should be used. We understand that a certification program will be developed under the MRR, as an alternative to verification. This should be recognized in the Cap and Trade Regulation too. Ideally, the term “certification” should be defined in both the MRR and the Cap and Trade Regulation. Modify section 95852(b)(5) as follows:

> (5) <u>There is no compliance obligation for CO2 emissions from e</u>~~E~~lectricity generated from use of biom<u>ass-derived fuels that</u>~~ethane must~~ comply with section 95852.2, and ~~must~~ meet verification<u> or certification</u> requirements for use of biom<u>ass-derived fuels</u>~~ethane~~ pursuant to MRR. (SCPPA7)
>
> **Response:** We deleted sections 95852(b)(5) and 95852(b)(7)(a)(4), so these comments are no longer relevant. We note that emissions from electricity generation that are emissions without a compliance obligation pursuant to sections 95852.1, 95852.1.1, and 95852.2, are not included in the compliance obligation for either electricity importers or California first deliverers. If emissions without a compliance obligation are emitted by a power plant from which electricity is imported, the emission factor for the power plant is calculated using only emissions that have a compliance factor. No part of an electricity importer’s compliance cost results from emissions without a compliance obligation.

Resource Shuffling

I-57. (multiple comments)
Comment: If not deleted, section 95852(b)(1) regarding resource shuffling should be revised. First, the conclusive statement that resource shuffling is “fraud” should be eliminated. Section 95852(b)(1) prohibits resource shuffling. The statement that resource shuffling is “fraud” adds nothing to the force or effect of the prohibition. However, as pointed out at the July 15, 2011, workshop on the Discussion Draft, “fraud” is a shrill term that suggests that the Board is biased and intemperate. The term is inappropriate and should be deleted. (SCPPA6)

Comment: SMUD believes that the 15 Day language covering Resource Shuffling in sections 95802 and 95852 has potential to significantly and negatively impact the current operation of electricity markets and distribution and transmission operations. Appearing without a workshop, other notice or public discussion, a long definition of “Resource Shuffling” has been added to the Regulation (section 95802(a)(245)) along with prohibitions against use of resource shuffling in section 95852(b), and addition of a requirement for a personal attestation that resource shuffling, as defined, has not occurred. There are several levels at which this set of newly introduced concepts and regulatory language is unworkable. Prior public discussion would certainly have disclosed this.

SMUD recommends that ARB hold a public workshop in the near future giving stakeholders the opportunity to discuss and provide input on the issue of the treatment of out-of-state renewable and other electricity resource purchases under the Cap and Trade and Mandatory Reporting Regulations. Additionally, various other portions of this and other regulations address specific issues associated with emission claims due to expiring coal contracts and out-of-state renewable energy contracts. For example, SB 1368 prevents California utilities from contracting with or extending long-term, baseload contracts for new or existing generation with emissions factors greater than 1,100 lbs/MWh. Legacy out-of-state nuclear and hydro are prevented from being contract shuffled via the MRR. Existing out of state eligible renewable energy sources that commenced operation prior to 2005 are ineligible for the State's RPS unless imported to California prior to 2010. It is unlikely that regulated parties would have incentives to engage in a type of resource shuffling with existing out of state renewable resources that will not provide eligibility for RPS compliance. For the most part, then, only existing natural gas fired resources are at issue.

Natural gas resources are marginal resources active in high volume in short and long term markets that have emissions profiles relatively close to and both above and below the current CARB defined default emissions factor. It would be impossible for a power purchaser in this market to predict the emissions consequence, beyond their own emissions liability, of any transaction. The counterfactual nature of the "Resource Shuffling" definition renders its application impractical. Faced with potential personal allegations of fraud for consequences beyond the contractual horizon and beyond control, contracting for resources would be negatively impacted. Liquidity in this market is essential to the normal operation of the electric transmission and distribution systems. This rulemaking has had much deliberation on the use and setting of a default emissions value for imported power. This long process has resulted in workable values and application within the regulation which define the emission obligation for imported power.

The new resource shuffling language, both in definition and regulatory application, defines emissions obligations and "acceptable" emissions reductions in a way that essentially ignores this good work and places stakeholders participating in normal electricity markets at risk of significant legal consequence for normal market actions that have unknown and essentially unknowable, but relatively minor, GHG emission consequences. SMUD suggests that the Cap and Trade regulatory language in this regard revert to the 45 Day language in the October 2010 Regulation, without reference to resource shuffling, as most transactions that are truly worrisome are already prohibited or greatly discouraged by existing law, and the remaining transactions are too indistinguishable from normal market transactions to clearly delineate without implications that will curtail normal market transactions and potentially affect the reliability of the electricity system. Modify section 95802(a)(245) as follows:

"Resource Shuffling" means any plan, scheme, or artifice to receive credit based on emissions reductions that have not occurred, involving the delivery of electricity to the California grid, for which:

(A) An emission factor below the default emission factor is reported by a first deliverer of electricity pursuant to MRR for a generation source that has not historically served California load (excluding new or expanded capacity). And, during the same interval(s), the same first deliverer of electricity knowingly and actively participated in transactions resulting in delivery of electricity from a source with higher emissions ~~was delivered~~ to serve load located outside

California and in a jurisdiction that is not linked with California's Cap-and-Trade Program; or
(B) The default emission factor or a lower emissions factor is reported pursuant to MRR, for electricity that replaces electricity with an emissions factor higher than the default emission factor that previously served load in California; except when the replaced electricity no longer serves California load as a result of compliance with the Emission Performance Standards adopted by the California Energy Commission and the California Public Utilities Commission pursuant to Senate Bill 1368 (Perata, Chapter 598, Statutes of 2006).

And modify section 95852(b)(1) as follows:

(1) Resource shuffling is prohibited~~,~~ and is a violation of this article ~~and is a form of fraud~~. ARB will not accept a claim that emissions attributed to electricity delivered to the California grid are at or below the default emissions factor for unspecified electricity specified pursuant to MRR July 2011 section 95111 if that delivery involves resource shuffling. The following attestations must be submitted to ARB annually in writing, by certified mail only:
(A) "I certify under penalty of perjury of the laws of the State of California that [facility or company name] has not engaged in the activity of resource shuffling to reduce compliance obligation for emissions, based on emission reductions that have not occurred as an active and knowing part of my transaction."
(B) "I understand I am participating in the Cap-and-Trade Program under title 17, California Code of Regulations, article 5, and by doing so, I am now subject to all regulatory requirements and enforcement mechanisms of this program and subject myself to the jurisdiction of California as the exclusive venue to resolve." (SMUD3)

Comment: It is unclear how a first deliverer would be able to know in advance whether a transaction involved resource shuffling. For example, under subparagraph (B) of the definition, "resource shuffling" would occur if a covered entity received a delivery of electricity to the California grid for which the default emission factor is reported and the electricity "replaces electricity with an emissions factor higher than the default emission factor that previously served load in California." Many wholesale transactions including daily or hourly trades involve the purchase of system power which would be assigned the default emission factor under the ARB's Regulation for the Mandatory Reporting of Greenhouse Gas Emissions (MRR). For a covered entity in California that has gas-fired or other generation resources that have an emissions factor that is higher than the emissions factor of system power, any one of those purchases of system power could result in the replacement of higher emissions factor electricity without the trader having any idea that a replacement would occur.

The ambiguity of the term "historically served California load" in subparagraph (A) of the definition would likewise make it difficult for covered entities to know if they were engaged in resource shuffling or not. Under subparagraph (A) of the definition, a covered entity would be guilty of resource shuffling if the entity took delivery of electricity from a power plant with a low emissions factor and the plant “has not historically served California load.” However, the term “historically served California load” is undefined in the regulation. If electricity purchasers do not know the meaning of the term, they may avoid any purchases from out-of-state power plants with low emission factors regardless of how much the plant has served California to be sure of avoiding a charge of resource shuffling. That could preclude purchases of otherwise available supply, distorting the wholesale market and potentially increasing prices to consumers. Subparagraph (B) of the definition [Resource Shuffling] could have another counterproductive consequence. A covered entity may desire to permanently retire a power plant that has an emissions factor that is higher than the default emissions factor and replace the output of the plant with unspecified system power. The consequence of retiring the high-emitting plant would be to reduce GHG emissions, but the retirement would be precluded by the fact that the replacement of the output of the plant with unspecified system power would be penalized as resource shuffling. Perversely, under subparagraph (B) the covered entity could avoid a resource shuffling charge if the covered entity replaced the output of the plant with electricity that has an emissions factor that is higher than the default emissions factor. The result could be higher net emissions after retiring the power plant in comparison to the prohibited retirement combined with replacement at the default emissions factor.

Even more perversely, subparagraph (B) would allow the plant to be retired and replaced with system power if the retirement were the result of the SB 1368 Emissions Performance Standard (EPS) being applied to the plant, effectively requiring the covered entity to continue operating the plant and emitting GHG at a higher level until shut-down is required under the EPS. The ultimate irony is that subparagraph (B) would apply even if the high emissions plant were fully retired and replaced with a new zero emissions renewable resource before retirement was required by the EPS. Subparagraph (A) contains an exception for deliveries of low emission electricity from “new or expanded” low emission resources, but there is no such exception in subparagraph (B). The definition of “Resource Shuffling” is replete with problems that could have substantial negative consequences. The definition and the related provisions should be deleted from the “15-day” Regulation and reserved for consideration in a separate proceeding in which the provisions can be refined to achieve the proper objectives of AB 32 without having so great a potential for negative outcomes. If the resource shuffling provisions are not deleted and held for future consideration, at bare minimum they should be revised. First, the first sentence of the definition should be revised to make it clear that the definition applies only to deliveries to the California grid from a jurisdiction that is not linked with the California Cap and Trade program.

The definition in section 95802(a)(245)(A) should be revised to refer to a new defined term, “historically consumed in California” and to make other changes to conform to the use of the new defined term. Modify section 95802(a)(245) as follows:
(245) “Resource Shuffling” means any plan, scheme, or artifice to receive credit based on emissions reductions that have not occurred, involving the delivery of electricity <u>generated outside California and in a jurisdiction where a GHG emissions trading</u>

system has not been approved for linkage by the Board pursuant to subarticle 12 to the California grid, for which:

(A) An emission factor below the default emission factor is reported pursuant to MRR for electricity generated at a generation source that is~~has~~ not electricity historically consumed in~~served~~ California, as defined in section 95802(a) ~~load~~ (excluding electricity from new or expanded capacity) (such electricity being "Relevant Electricity"). And, during the same interval(s), electricity with ~~higher~~ emissions equal to or higher than the default emission factor was delivered to serve load located outside California and in a jurisdiction that is not linked with California's Cap-and-Trade Program which was previously served by the Relevant Electricity now used to serve load in California.~~; or~~

The definition of the new defined term, "historically consumed in California," should be based on section 95111(g)(4)(A) of the Mandatory Reporting Regulation. SCPPA recommends the following definition of "historically consumed in California:" Modify section 95802 as follows

95802(a)(X) "Electricity Historically Consumed in California" means electricity from a specified source of electricity located outside California that was reported in a 2009 verified data report and either:

(A) The electricity is claimed for the current data year by the same electricity importer that imported electricity from that specified source in 2009, based on a written power contract or status as a generation providing entity (as defined in MRR) in effect prior to January 1, 2010, that remains in effect, or that has been renegotiated for the same facility or generating unit for up to the same share or quantity of net generation within 12 months following prior expiration; or

(B) The electricity is claimed for the current data year by a different electricity importer than the entity that imported electricity from that specified source in 2009, but at least the same share or quantity of net generation from that specified source was imported into California in 2009 (as reported in a 2009 verified data report). (SCPPA6)

Comment: The Cap and Trade Regulation must allow for ordinary grid operations which facilitate the delivery of renewable energy resources into the State of California. Under the current definition, of "resource shuffling," Iberdrola Renewables is concerned normal provision of balancing and operating reserves to enable the reliable import of renewable energy would be defined as "fraudulent," which it is not. The import of renewable energy into the State of California is an important component of California's renewable portfolio and necessary for California to meet its RPS requirements. Significant work has gone into the development of the California RPS requirements which will govern the portfolio content requirements. It is critical that the Cap and Trade Regulation be aligned with the RPS requirements to ensure effective and consistent delivery of reliable renewable energy into the State of California. (IBERDROLA)

Comment: The definition of resource shuffling should be revised to exclude situations where a covered entity either unknowingly engages in activities that resemble resource shuffling, or adjusts its portfolio for valid economic dispatch reasons. Modify section 95802(a)(245) as follows:

> (245) "Resource Shuffling" means any <u>intentional</u> plan, scheme, or artifice to receive credit based on emissions reductions that have not occurred, involving the delivery of electricity to the California grid, for which:
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> (A) An emission factor below the default emission factor is reported pursuant to MRR76 for a generation source that has not historically served California load (excluding new or expanded capacity and grandfathered contracts). <u>New or expanded capacity is relative to capacity as of 01/01//2012.</u> And, during the same interval(s), <u>the same entity reporting the lower emissions delivers</u> electricity with higher emissions ~~was delivered~~ to serve load located outside California and in a jurisdiction that is not linked with California's Cap and Trade Program; or
>
> (B) The default emission factor or a lower emissions factor is reported pursuant to MRR, for electricity that replaces electricity with an emissions factor higher than the default emission factor that ~~previously~~ served load in California <u>prior to 01/01/2012</u>; except when:
>
> (1) the replaced electricity no longer serves California load as a result of compliance with the Emission Performance Standards
>
> (2) the contract with the resource was terminated prior to 01/01/2012.
>
> (SCE3)

Comment: The definition of resource shuffling and rules for specifying imports must be modified to be more consistent with wholesale energy markets. WPTF is concerned that the new provisions in the modified Regulation that characterize resource shuffling as a violation and a form of fraud, may result in electricity importers being subject to severe financial and potentially criminal consequences for events that are outside that entity's control. For instance, one of the conditions for resource shuffling, as defined, is that "during the same interval(s), electricity with higher emissions was delivered to serve load located outside California and in a jurisdiction that is not linked with California's cap and trade program." This condition is a direct result of economic dispatch, not resource shuffling.

Second, the definition for resource shuffling for low-emission resources should not apply to all generation, but should be limited to those resources which have the potential to undermine the environmental integrity of the cap and trade program—namely large hydro-electric and nuclear generation. Natural gas generation should not be considered a "shuffle-able‟ resource. Natural gas generation is dynamic throughout the WECC; it naturally moves from market to market depending on load and transmission conditions. Restrictions on claims to natural gas generation under the cap and trade program will inhibit normal market transactions and reduce the liquidity of the California power markets.

The requirement that a generation source has historically served load would have a particularly chilling effect. This provision would disadvantage natural gas resources that have chosen to sell through markets rather than bilateral contracts, as they could not meet the historic test for specifying imports into California. Conversely, resources that have historically imported into California under bilateral contracts would be forced to extend those contracts in order to maintain eligibility for a specified emission rate for their imports. As the California Independent System Operator continues to move toward competitive bid-based spot markets for energy and ancillary services, CARB should not be adopting regulations that disincentivize competitive market behavior.

WPTF recommends several changes to the modified regulation to address these concerns. First, the condition regarding electricity with higher emissions being delivered to serve load located outside California should be eliminated. Second, natural gas generation should be considered a "non-shuffle-able" resource. Third, the historic consumption should not be an eligibility requirement for specification of natural gas resources. Given the complexity of issues surrounding imported electricity, WPTF urges CARB to hold a technical workshop on these matters prior to finalization of the rule.

When an out-of-state resource serves load in California, by necessity another unit up the dispatch curve, usually with a higher emission rate, will necessarily serve the incremental load in the source jurisdiction. This is a normal and intended consequence of power markets, and completely out of the control of the importing entity. We recommend changing the requirements for attestation in recognition of the fact that resource shuffling is a consequence of the market, and not necessarily under an individual entity's control. (WPTF2)

Comment: The definition for resource shuffling for low-emission resources should not apply to all generation, but should be limited to those resources which have the potential to undermine the environmental integrity of the cap and trade program, namely large hydro-electric and nuclear generation. Natural gas generation should not be considered a "shuffle-able" resource. Natural gas generation is dynamic throughout the WECC. It naturally moves from market to market depending on load and transmission conditions. Restrictions on claims to natural gas generation under the cap and trade program will inhibit normal market transactions and reduce the liquidity of the California power markets. Modify section 95802(a)(245)(A) as follows:

> (A) An emission factor below the default emission factor is reported pursuant to MRR <u>for electricity generated at a hydroelectric facility over 30 MW, or a nuclear generating facility</u> ~~a generation source~~, that has not historically served California load (excluding new or expanded capacity). ~~And, during the same interval(s), electricity with higher emissions was delivered to serve load located outside California and in a jurisdiction that is not linked with California's Cap-and-Trade Program; or~~ (WPTF2)

Comment: The proposed Regulation's definition of "resource shuffling" is overly broad and could operate as a strong disincentive to future dispatch and contracting of highly efficient out-of-state resources with emissions lower than the default emissions rate for unspecified power. We recommend that CARB clarify that the prohibition on resource shuffling was not intended to apply to circumstances where existing facilities that have historically served California deliver more power to California in the future. Modify section 95802(a)(245)(A) as follows:

(A) An emission factor below the default emission factor is reported pursuant to MRR for a generation source that has not historically served California load (excluding new or expanded capacity~~. A~~and, during the same interval(s), electricity with higher emissions was delivered by the same covered entity or any entity with which it has a direct or indirect corporate association to serve load located outside California and in a jurisdiction that is not linked with California's Cap-and-Trade Program; provided, however, that nothing in this paragraph shall be deemed to prohibit reporting a lower than the default emissions factor pursuant to the MRR for increased deliveries of electricity to California, in MWh per year, from a generating source that has historically served California; or (CALPINE3)

Comment: SCE supports ARB's discouragement of resource shuffling, which is consistent with AB 32's direction that emissions reductions be "real." However, it is entirely possible that an entity may inadvertently commit resource shuffling, under the rules as currently written, without any fraudulent intent or scheme to receive an unearned emissions reduction. For example, a simple human error in reporting or interpretation of a rule could result in the appearance of resource shuffling. SCE agrees that truly fraudulent resource shuffling should be addressed, but notes that it will often be premature to immediately conclude that fraud is involved. ARB should be careful to not restrict an electricity deliverer's ability to procure the least-cost electricity (assuming the GHG costs are adequately incorporated into these prices). Modify section as follows:

95852(b)(1) Resource shuffling is prohibited~~,~~ and is a violation of this article ~~and is a form of fraud~~. ARB will not accept a claim that emissions attributed to electricity delivered to the California grid are at or below the default emissions factor for unspecified electricity specified pursuant to MRR section 95111 if that delivery involves resource shuffling. (SCE3)

Comment: NCPA has concerns regarding the ambiguity and confusion associated with the definition of resource shuffling, and joins with the recommendation of the Joint Utilities asking that CARB strike this definition unless and until a definition can be crafted that narrowly defines the malfeasance only, and does not adversely impact electricity operations statewide. For purposes of this section 95852(b)(1), intentionally under reporting or misreporting emissions in an attempt to obtain credit for emissions reductions that have not occurred should be prohibited. However, the consequences of violating this prohibition should encompass the same penalty processes as the rest of the Program. Modify section 95852(b)(1) as follows:

> Section 95852 (b)(1): Resource shuffling is prohibited, <u>and</u> is a violation of this article ~~and is a form of fraud. ARB will not accept a claim that emissions attributed to electricity delivered to the California grid are at or below the default emissions factor for unspecified electricity specified pursuant to MRR section 95111 if that delivery involves resource shuffling. The following attestations must be submitted to ARB annually in writing, by certified mail only:~~
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> > ~~(A) "I certify under penalty of perjury of the laws of the State of California that facility or company name] has not engaged in the activity of resource shuffling to reduce compliance obligation for emissions, based on emission reductions that have not occurred."~~
> >
> > ~~(B) "I understand I am participating in the Cap-and-Trade Program under title 17, California Code of Regulations, article 5, and by doing so, I am now subject to all regulatory requirements and enforcement mechanisms of this program and subject myself to the jurisdiction of California as the exclusive venue to resolve."~~ (NCPA3)

Comment: Resource and contract shuffling enables covered entities to meet their compliance obligations without generating any net emissions reduction, and is therefore at odds with the objectives of the program. While we support ARB's intent to prohibit resource shuffling, we ask that ARB conduct a workshop to flesh out the details and consider the ramifications of implementing the provision and definition of resource shuffling provided in the draft rule. To be effective, it is critical that ARB's definition not create loopholes, send mixed incentives, or unduly inhibit covered entities' efforts to reduce the carbon intensity of their resource mix. We feel additional clarification is required to make that assessment.

One modification we recommend ARB make at this stage is to expand the exception for compliance with the Emission Performance Standard (EPS) adopted by the PUC and CEC pursuant to SB 1368. The current definition of resource shuffling excludes electricity no longer serving California load "as a result of" compliance with the EPS. We ask that ARB expand the current language to clarify that actions taken by covered entities to achieve early compliance with the EPS are similarly not prohibited as resource shuffling. (KUSTIN16)

Comment: The Joint Utilities agree that any artificial attempts to distort the actual emissions reductions achieved by a first deliverer of electricity should be prohibited. However, the 15-Day Language on resource shuffling has the potential to negatively impact the state's electric system distribution and transmission operations and should be subject to additional stakeholder discussions and review. The definition of Resource Shuffling in section 95802(a)(245) and its application in section 95852(b)(1) must be changed. (JOINTUTILITIES)

Comment: The regulation does not make clear whether an out-of-state power plant could fall within the definition of "resource shuffling" if the facility reported a portion of its output "historically serving" California, but then enters into a new contract for the remaining capacity. Thus, in addition to IEP's concern that the definition does not recognize an "intent to mislead," such a presumptive determination solely based on a historical contract ignores the situation of merchant facilities as well as assets coming off of term contracts that will require flexibility in entering new contracts. Reference to "fraud" should be deleted. Modify section 95852(b)(1) as follows:

> (1) Resource shuffling is prohibited and is a violation of this article. ~~and is a form of fraud.~~ ARB will not accept a claim that emissions attributed to electricity delivered to the California grid are at or below the default emissions factor for unspecified electricity specified pursuant to MRR section 95111 if that delivery involves resource shuffling, unless the resource has been registered as a specified import. The following attestations must be submitted to ARB annually in writing, by certified mail only:
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> (A) "I certify under penalty of perjury of the laws of the State of California that [facility or company name] has not intentionally engaged in the activity of resource shuffling to reduce compliance obligation for emissions, based on emission reductions that have not occurred.
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> (B) "I understand I am participating in the Cap-and-Trade Program under title 17, California Code of Regulations, Article 5, and by doing so, I am now subject to all regulatory requirements and enforcement mechanisms of this program and subject myself to the jurisdiction of California as provided in title 17, California Code of Regulations, article 5, as the exclusive venue to resolve dispute brought pursuant to this Article.
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> IEPA recommended that the resource shuffling prohibition should append the words "unless the resource has been registered as a specified source" to the second sentence of section 95852(b)(2). This modification would render the prohibition against resource shuffling meaningless, since it would imply that an import was a specified source rather than an entity, and because electricity entities that are recognized as specified sources pursuant to MRR requirements could be used as part of a resource shuffling scheme if two or more entities colluded to launder the electricity.

The definition for resource shuffling should be clarified to exclude legitimate transactions and only apply to situations where an entity knowingly and intentionally misrepresents its emissions for purposes of avoiding the compliance obligation. Reference to "fraud" should be deleted. (IEPA2)

Comment: Modify section 95802(a)(245) as follows:

> (245) "Resource Shuffling" means any plan, scheme, or artifice to intentionally misstate or mislead regarding the ~~receive credit based on~~ emissions rate ~~reductions that have not occurred~~, involving the delivery of electricity to the California grid~~,~~ by an entity that has not already registered under the Mandatory Reporting Regulation as a specified importer for which:

(A) An emission factor below the default emission factor is reported pursuant to MRR for a generation source that has not ~~historically~~ served California load (excluding new or expanded capacity) ~~. A~~ and, during the same interval(s), electricity with higher emissions was delivered to serve load located within ~~outside~~ California ~~and in a jurisdiction that is not linked with California's Cap-and-Trade Program; or~~

~~(B)The default emission factor or a lower emissions factor is reported pursuant to MRR, for electricity that replaces electricity with an emissions factor higher than the default emission factor that previously served load in California; except when the replaced electricity no longer serves California load as a result of compliance with the Emission Performance Standards adopted by the California Energy Commission and the California Public Utilities Commission pursuant to Senate Bill 1368 (Perata, Chapter 598, Statutes of 2006).~~ (PACIFICOR3, IEPA2)

Comment: The resource shuffling provisions as proposed in the 15-day modifications are vague and overly broad, violate the intent of the cap-and-trade regulation, create the Commerce Clause issues, and contradict CPUC requirements of utilities to undertake least cost dispatch. While restrictions may be needed, it is important to draft such restrictions in a manner that does not treat legitimate electricity market transactions as a crime. Because such extensive changes are needed, we recommend that ARB follow-up with a stakeholder process, including a workshop and additional comments, to further refine the rules to meet the disparate concerns of market participants. The first change required is to modify the definition of resource shuffling to narrow it to three types of resource shuffling: 1) importing power from a low emitting resource in place of a higher emitting resource from the supplier's same portfolio of resources; 2) selling high emitting power from a facility owned or under long-term contract out-of-state and replacing it with low emitting or unspecified imported power; and 3) moving energy from high emitting specified resources around the WECC so that it origins cannot be traced and it is assigned the default emissions factor. A fourth type of transaction could be resource shuffling but cannot be prevented due to Commerce Clause issues: A single generation facility that is low emitting will gain a benefit by selling into the California market where it previously had not, while a coal facility may not economically dispatch into California because of its high GHG cost. This type of economic shuffling, and the resulting leakage, cannot be prevented due to the Commerce Clause. The Resource Shuffling definition should also make it clear that the importer of the electricity and not the buyer is the sole entity that is engaging in resource shuffling. Buyers of electricity, or facilitators of electricity transactions such as the CAISO, should not have to investigate every import transaction to see if the electricity source is properly reported. To do otherwise would destroy markets for electricity and require all transactions to be bilateral with specified resources to avoid transactions being deemed fraudulent by ARB. Additionally, the definition needs to be clarified to make it clear that resource shuffling only occurs as a result of intentionally underreporting. Finally, no attestations should be required since resource shuffling properly defined would be a misreporting of emissions and subject to enforcement pursuant to the MRR provisions on inaccurate reporting as well as Section 96014(c) of the Cap-and-Trade Regulation. The attestations serve no useful purpose, but do tend to raise the specter that perfectly valid conduct might be treated as inconsistent with the attestation. Further, as resource shuffling is currently defined in the 15-day modifications, it is not a fact, but a legal opinion, and therefore cannot be attested to. For example any sale of electricity from a facility other than coal existing in the WECC that did not deliver electricity to California in 2009 may be legally considered by the Cap-and-Trade Regulation as engaging in resource shuffling. A single facility, on the other hand, may rightly believe it is impossible for it to "resource shuffle" if it has no other resources. The following offers one way of potentially narrowing the definition of "resource shuffling," but it is not the only way of dealing with the issue. For example, restoration of the language regarding hydroelectricity, nuclear power, and high-emitting resources that was deleted in the 15-day modifications could also go a long way toward correcting part of the problem. Modify sections 95802(a)(245) and 95852(b)(1) as follows:

> (245) "Resource Shuffling" means ~~any plan, scheme, or artifice to receive credit based on emissions reductions that have not occurred, involving the delivery of electricity to the California grid, for which~~ intentionally underreporting emissions of imported electricity in any of the following ways and does not include transactions entered into for operational purposes as demonstrated according to the provisions in section 95111(b)(2) of the MRR:
>
> > (A) An emission factor below the default emission factor is reported pursuant to MRR for a generation ~~source~~ facility or unit of an asset-controlling supplier that has not historically served California load (excluding new or expanded facility or unit capacity). And, during the same interval(s), electricity from the same asset-controlling supplier with higher emissions was delivered to serve load located outside California and in a jurisdiction that is not linked with California's Cap-and-Trade Program; or
> >
> > (B) The default emission factor or a lower emissions factor is reported pursuant to MRR, for electricity that replaces electricity with an emissions factor higher than the default emission factor that ~~previously serve~~s~~d~~ load in California pursuant to an ownership interest or long-term contract; except when the ~~replaced~~ higher emitting electricity no longer serves California load as a result of compliance with the Emission Performance Standards adopted by the California Energy Commission and the California Public Utilities Commission pursuant to Senate Bill 1368 (Perata, Chapter 598, Statutes of 2006) ; or
> >
> > (C) Specified electricity with an emissions factor higher than the default emission factor is knowingly reported by the electricity importer as unspecified electricity.
>
> (1) Resource shuffling is prohibited, is a violation of this article ~~and is a form of fraud. ARB will not accept a claim that emissions attributed to electricity delivered to the California grid are at or below the default emissions factor for unspecified electricity specified pursuant to MRR section 95111 if that delivery~~

~~involves resource shuffling. The following attestations must be submitted to ARB annually in writing, by certified mail only:~~

~~(A) "I certify under penalty of perjury of the laws of the State of California that [facility or company name] has not engaged in the activity of resource shuffling to reduce compliance obligation for emissions, based on emission reductions that have not occurred."~~

~~(B) "I understand I am participating in the Cap-and-Trade Program under title 17, California Code of Regulations, article 5, and by doing so, I am now subject to all regulatory requirements and enforcement mechanisms of this program and subject myself to the jurisdiction of California as the exclusive venue to resolve."~~ (SEMPRA3)

Comment: In addition, section 95852(b)(1) provides that "resource shuffling" constitutes fraud. Fraud is a criminal violation that is imposed when there is intent to deceive or misrepresent the truth. Numerous parties have expressed concern about the lack of clarity regarding the definition, that they do not understand the definition, and that they do not know whether otherwise legitimate and routine transactions in today's interstate market could now become criminal actions under the proposed Cap and Trade regulation. LS Power requests that the Board remove this issue from the proposed regulations. This can be done by either deleting the reference to fraud in Section 95852(b)(1), or making it clear in the definition of Resource Shuffling at section 95802(a)(245) that the definition only applies when an entity intends to misrepresent the nature of imports that were actually made into California. (LSPOWER)

Comment: Section 95802(a)(245)(A) identifies a resource shuffling scenario, where electricity is delivered into the California grid for which "an emission factor below the default emission factor is reported…for a generation source that has not historically served California load (excluding new or expanded capacity)," and that "during the same interval(s), electricity with higher emissions was delivered to serve load" outside California's Cap and Trade program. It is unclear what ARB means by "new or expanded capacity." Compliance entities will need a reference date from which to calculate "new or expanded capacity," or they may unknowingly engage in activities that seem, under these rules, like resource shuffling. SCE recommends that ARB introduce such a date and clarify this rule. (SCE3)

Comment: In the definition for "resource shuffling" at section 95802(a)(245)(b), ARB uses the term "previously served load in California." This term is central to the meaning of the defined category and is not defined in the rule. If this clause is intended to have a meaning different from "historically served California load" in the first category, then Powerex requests that ARB explain the difference and clearly define both terms in the rule. If the two terms are meant to describe the same generation sources, then only one term should be used and clearly defined in the rule. (POWEREX)

Comment: In the proposed modifications to the Cap and Trade Rule, ARB broadly defines the term "resource shuffling" to include a "plan, scheme, or artifice to receive credit based on emissions reductions that have not occurred, including [sic] the delivery of electricity to the California grid." The definition goes on to more specifically define two distinct forms of resource shuffling (section 95802(a)(245)). Subsection (A) of the definition distinguishes between sources that have "not historically served California load" and those that have. This clause, however, is not defined in the Cap and Trade Rule. As the concept is central to the meaning of the defined category, Powerex requests that ARB define the term to clearly state what constitutes "historically serving California load" for purposes of identifying resource shuffling. (POWEREX)

Comment: Section 95802(a)(245)(A) is ambiguous and either unnecessary or likely to be ineffective at curbing resource shuffling. If electricity with an emission factor below the default is reported for a generation source that has not historically served California load, it is likely that electricity with higher emissions will have been delivered, during that same interval, outside California and unaffected by California's Cap and Trade Program. As written, therefore, the second sentence of subsection (A) does not narrow or clarify the subsection, and it could be deleted without changing the scope or meaning of the subsection. If ARB intended subsection (A) to be read as applying to a single entity i.e., applying to a situation where a single entity delivered electricity with higher emissions to a load outside California during the same interval as the specified import, then subsection (A) is unlikely to successfully restrict resource shuffling. It is possible that two entities could exchange electricity so that one has all of the electricity with a lower emission factor and the other has all of the electricity with a higher emission factor. The entity with the lower emission factor electricity then could send electricity below the default emission factor without delivering electricity with higher emissions to a load outside of California. Powerex recommends eliminating the second sentence of subsection (A) to prevent this kind of circumvention of the Cap and Trade Rule. (POWEREX)

Comment: Subparagraph (B) of the definition of "Resource Shuffling" should be deleted in its entirety. Subparagraph (B) would have the potential for consequences that are contrary to the purpose of AB 32. The subparagraph would have the potential to discourage a covered entity from permanently retiring a power plant before being required to do so under the EPS. The covered entity could only avoid a resource shuffling charge only by replacing the output of the retired plant with electricity within an emission factor higher than the default emissions factor. The subparagraph would discourage a covered entity from retiring a high emissions plant and replacing the plant with a renewable resource before retirement as required by the EPS. (SCPPA6)

Comment: Section 95802(a)(245)(B) outlines a resource shuffling scenario in which "electricity… replaces electricity with an emissions factor higher than the default emission factor that previously served load in California; except when the replaced electricity no longer serves California load as a result of compliance with the Emission Performance Standards" adopted pursuant to Senate Bill 1368. There is no reference date from which to calculate whether electricity had "previously" served load. In addition, this provision may penalize compliance entities for decisions made prior to the release of this revised Regulation. For example, if a compliance entity had decided before the beginning of the Cap and Trade program to fully divest itself of generation from a higher-emitting facility, it could be considered resource shuffling as currently defined under the draft rules. Moreover, this scenario restricts utilities from adjusting their portfolios for valid economic dispatch reasons. A number of factors contribute to this economic valuation, many of which could change over the coming years due to forces outside the control of ARB or any compliance entities. (SCE3)

Comment: The definition of resource shuffling is problematic as drafted, because it could be interpreted to prohibit standard and existing electric transactions that maximize the efficient use of the State's limited electric transmission system and interferes with economic dispatch of electric generation resources. The proposed definition goes far beyond Staff's stated intent of minimizing leakage and ensuring the integrity of the Cap-and-Trade Program. Like the Joint Utilities, NCPA believes that the proposed definition for resource shuffling (as well as the related provisions of section 95852(b)(1)) must be publicly vetted in order to ensure that Staff fully understands the implications of such a drastic revision to the Proposed Regulation and the significant ramifications it creates for electrical distribution utilities.

NCPA agrees that any "plan, scheme, or artifice to receive credit based on emissions reductions that have not occurred" should be prohibited. However, the proposed definition would penalize those that participate in legitimate transactions, and indeed, would impact not only existing utility and electricity market operations, but long standing contractual commitments as well. While the proposed definition acknowledges generation resources that have historically served California load, it provides no guidance on interpreting historical sales, nor does it acknowledge that certain contractual transactions that may not meet this exclusion are merely the result of existing agreements or efficient economic dispatch of generation resources. Clearly, this cannot be Staff's intent. Accordingly, NCPA urges Staff to delay any formal action regarding the concept of resource shuffling until after such time as Staff has had an opportunity to hold a public workshop on this important issue. (NCPA3)

> **Response:** Several commenters see resource shuffling as a problem that the regulation must address, and we thank these commenters for supporting our intent to prohibit resource shuffling. As defined in the regulation, "resource shuffling" means any plan, scheme, or artifice to receive credit based on emissions reductions that have not occurred, involving the delivery of electricity to the California grid.
>
> Based on the comments of SMUD, SCPPA, and many others, we made significant improvements in the second 15-day changes to the regulation to both the definition of resource shuffling, in section 95802(a)(245) (newly numbered as paragraph (251) of that section) and to the resource shuffling prohibition, section 95852(b)(1) (newly numbered as paragraph (2) of that section).
>
> We deleted the words "for which" in the definition and deleted paragraphs (251)(A and B) addressing the commenters' concerns regarding these paragraphs. We modified the prohibition against resource shuffling, removing

the words “and is a form of fraud” as requested. We also deleted the second sentence of section 95852(b)(2). Furthermore, we modified the attestations of 95852(b)(2)(A and B).

We do not believe that the resource shuffling provisions, as modified, will negatively impact the current operation of electricity markets or facility operations, or that the concepts or language as modified are unworkable. However, because this regulation puts a price on GHG emissions, we expect the regulation to influence electricity markets in California. Requiring allowances for GHG emissions from electricity generation is intended to create a level playing field based on consideration of GHG emissions for high-emitting generation resources compared to low- or zero-emitting resources.

As recommended by SMUD and others, we held a technical workshop on August 26 that included discussion of out-of-state renewable electricity, resource shuffling, and other aspects of imported electricity. We also continued informal discussions with stakeholders regarding the resource shuffling definition and the prohibition.

While SMUD is correct about what SB 1368 prevents, this does not preclude resource shuffling involving coal resources. Furthermore, the MRR does not prohibit resource shuffling, nor does it prevent “contract shuffling,” which, although essentially equivalent in meaning, is a phrase not defined in this regulation or in the MRR. Instead, the MRR only requires certain reporting about imported electricity from these sources. While we agree that regulated parties might not have incentives to engage in resource shuffling with existing out-of-state renewable resources, some parties may do so if it is not prohibited. For example, if a renewable facility is used in Oregon to meet an RPS requirement, and its electricity sinks, i.e., has a final point of delivery, in Oregon before this regulation takes effect, a marketer owning the electricity and RECs could enter a new contract with a third party to sell the electricity into California. This would likely be a form of resource shuffling. While such a scheme could theoretically be avoided by a multi-jurisdictional regulatory regime that assigned deemed emissions to “null power,” such a regime does not exist and is not under consideration for WCI. SMUD has not provided any reason to say that only existing natural gas-fired resources are at issue for resource shuffling.

In modified section 95802(a)(251), resource shuffling is defined as “any plan, scheme, or artifice to receive credit based on emissions reductions that have not occurred, involving the delivery of electricity to the California grid.”

Because resource shuffling is defined as a “plan, scheme, or artifice” unintentional conduct cannot result in resource shuffling. Therefore, an electricity importer need not be concerned with the “unknown and essentially unknowable” emissions consequences of the natural gas market transactions described.

There is no need to define resource shuffling as “intentional” or include that word in the prohibition because we believe that the legal meaning of the language in the definition makes such modification unnecessary. However, we agreed to some of the comments about the attestations required. As modified, the regulation now recognizes that the signer of the attestation is an agent of the facility or company for which the attestation is made, and we believe that this modification also meets the intent of most commenters’ requests regarding the attestations.

With regard to the SCPPA6 comment, we do not agree that a first deliverer would not know in advance if they engaged in a plan, scheme, or artifice to receive credit based on emissions reductions that have not occurred. First deliverers that enter into transactions without this intent are not engaging in resource shuffling. However, we note that it is not our intent to discourage any covered entity from retiring a high-emitting plant in California or out-of-state. We do not believe such early retirement could meet the definition of resource shuffling as modified. Furthermore, we encourage early compliance with the EPS. Such early compliance is not resource shuffling.

Finally, we note that there is much speculation about what might happen within electricity markets due to the prohibition of resource shuffling. While we believe that the regulation’s modified treatment of resource shuffling will not have negative effects on the market or system operations, we will continue to monitor its effects on the California electricity market before and after the regulation takes effect. We have already seen changes in how electricity is reported due to the mandatory reporting regulation and the expectation of the implementation of this regulation. We will also continue to work with stakeholders to ensure that the regulation is clear in its treatment of resource shuffling. If, in the future, we find that the regulation may create, or does create, undesirable or unintended effects, staff will consider asking the Board to modify the regulation, or will recommend other actions to prevent unintended negative consequences.

SCPPA6 recommends modifying the first sentence of the definition of resource shuffling. We do not agree that the definition should be limited such that it does not apply to electricity generated in a linked jurisdiction. We believe that some first deliverers could devise shuffling schemes that include electricity from a linked jurisdiction. For example, if an entity in a linked jurisdiction produced hydroelectricity and sold it to a marketer, the marketer could sell the hydroelectricity to a third party in an unlinked jurisdiction. If the third party owned high-emitting generation in the unlinked jurisdiction, and that generation had previously served California, the third party could now sell the hydroelectricity to California, and use the high emission electricity elsewhere. If the parties involved colluded in such a plan in order to reduce compliance obligations when there was not reduction in GHG emissions, such an “electricity laundering” plan could well be resource shuffling. Finally, because we deleted the phrase “electricity historically consumed in California" from the resource shuffling definition, there remains no reason to define it.

IBERDROLA is concerned that the provision of balancing and operating reserves to enable import of renewable energy would meet the definition of resource shuffling. We note that our treatment of RPS electricity, as modified, and discussed elsewhere, does not involve reducing the compliance obligation for GHG-emitting electricity imported for balancing and operations in support of renewable energy. Instead we provide a credit for most RPS electricity that is not directly delivered. Furthermore, even if we had not modified the regulation to include an RPS adjustment, we do not believe that normal provision of electricity for balancing or operations needs would fit the definition of resource shuffling.

We have already responded to the concerns raised in WPTF2's first and second paragraphs. We do not agree that natural gas generation cannot play a part in a resource shuffling plan, scheme, or artifice, because not all gas generation is dynamic throughout markets in the WECC; to the contrary, some natural gas generated electricity used by vertically integrated utilities to serve base load. When natural gas generation with an emission actor below the default emission factor is used for baseload by a utility in another jurisdiction, the regulation would provide an incentive for that utility to sell its relatively clean electricity for import into California, and purchase system electricity to serve its own load. While it is true that system electricity would likely cost more, if the differential cost was less than the carbon allowance cost per MWh, there is an opportunity for resource shuffling in which two or more parties share the economic gain resulting from shuffling.

Nonetheless, we have no intent to characterize, nor does the regulation as modified characterize, resource shuffling as the normal market transactions related to the purchasing, selling, and dispatch of natural gas generation that are not part of a plan, scheme, or artifice to receive credit based on emission reductions that have not occurred. We disagree that the resource shuffling prohibition should be resource-specific; for example, that it should be limited to large hydroelectric and nuclear generation. If natural gas generation is delivered to the California grid as part of a plan, scheme, or artifice to receive credit based on emission reductions that have not occurred, such shuffling should be prohibited.

Because we deleted section 95802(a)(251)(A and B), the regulation now makes no reference to whether or not a generation source has historically served load in California. We expect that the regulation as modified will not disincentivize competitive market behavior, and that it will appropriately minimize leakage that can occur through shuffling, while ensuring that compliance obligations for electricity delivered in California are equitable to importers and California generators. We do not agree that the modified definition and prohibition against resource shuffling will provide a disincentive to future dispatch and contracting of highly efficient out-of-state resources, because most dispatch and contracting for power from efficient resources is not resource shuffling.

WPTF2's fourth paragraph recommends three changes. The first has been discussed above and is no longer applicable due to our modifications. We disagree with the second recommended change because, as discussed above, natural gas generation can be part of a resource shuffling scheme. With regard to the third request, modified section 95852(b)(3) includes the requirements for specified sources, including natural gas sources, and historic consumption plays no role in the requirements. While the MRR previously had requirements for specified sources that considered historical consumption, the MRR was modified and information about historical consumption, while it must still be reported, is not used to determine whether a facility's electricity can be imported with claimed emissions that have been calculated with a specified source emission factor. We held a technical workshop to discuss resource shuffling and other issues regarding imported electricity on August 26 and modifications were made to the resource shuffling section and to parts of section 95852(b) to incorporate new informal input from stakeholders.

Finally, WPTF2 explains how generators are dispatched to serve incremental load in a source jurisdiction when an out-of-state resource serves California. We agree that this is a normal and intended consequence of market dispatch rules. However, this is clearly not an instance of resource shuffling as defined, because it is not a "plan, scheme, or artifice" to receive credit based on emissions reductions that have not occurred, involving the delivery of electricity to the California grid.

CALPINE3 comments that the definition in the first 15-day changes to the regulation could be a disincentive to future dispatch of efficient resources. We do not agree, because resource shuffling is defined as a plan, scheme or artifice to receive credit for GHG emissions reductions that did not occur. CALPINE3 also states that the definition "is overly broad." Again, we disagree. We believe the definition, as modified, is still specific to actions that are designed to reduce compliance obligation by manipulating the market in order to take advantage of differential electricity costs within California and other jurisdictions. We believe that deleted paragraphs (A) and (B) of the definition may have introduced ambiguity and unfounded concerns with respect to the remaining part of the definition. Many commenters failed to understand that the wording of the remaining part of the definition means that resource shuffling does not encompass unintentional conduct. We expect that with additional discussion and consideration of these provisions, commenters will gain a better understanding of resource shuffling. We expect that we will also continue to learn during this process. However, it may be difficult to understand all potential types of resource shuffling until they are either discussed or observed in practice. If during continued work with stakeholders, before and after the beginning of the first compliance period, we discover that this regulation would have negative unintended consequences, we will take appropriate steps to minimize or prevent such consequences, potentially including a initiating a new regulatory process to modify the regulation.

Nevertheless, in Resolution 11-32 the Board directed the Executive Officer to continue discussions with stakeholders to identify and propose, as necessary, during the initial implementation of the cap-and-trade program, potential amendments to the Regulation on the definition of Resource Shuffling to: (a) provide appropriate incentives for accelerated divestiture of high-emitting resources by recognizing that these divestitures can further the goals of AB 32, and (b) ensure that changes in reported emissions from imported electricity that serves California do not result merely in a shift of emissions within the Western Electricity Coordinating Council region, but instead reduces overall emissions.

I-58. Comment: The Board has proposed adding language to section 95852(b)(1) of the proposed California Cap on Greenhouse Gas Emissions and Market Based-Compliance Mechanisms that would prohibit first deliverers of electricity from engaging in resource shuffling by making such action a violation of the regulation and a form of fraud. The proposed Section 95852 would read, in relevant part, “Resource shuffling is prohibited, is a violation of this article, and is a form of fraud.” “Resource Shuffling” means

“Any plan, scheme, or artifice to receive credit based on emissions reductions that have not occurred, involving the delivery of electricity to the California grid, for which:
(A) An emission factor below the default emission factor is reported pursuant to MRR for a generation source that has not historically served California load (excluding new or expanded capacity). And, during the same interval(s), electricity with higher emissions was delivered to serve load located outside California and in a jurisdiction that is not linked with California’s Cap and Trade Program; or,
(B) The default emission factor or a lower emissions factor is reported pursuant to MRR, for electricity that replaces electricity with an emissions factor higher than the default emission factor that previously served load in California; except when the replaced electricity no longer serves California [sic] load as a result of compliance with the Emission Performance Standards adopted by the California Energy Commission and the California Public Utilities Commission pursuant to Senate Bill 1368 (Perata, Chapter 598, Statutes of 2006).”

Based on the plain reading of the proposal, CARB does not have authority to define resource shuffling as “fraud,” has proposed a vague definition of resource shuffling that does not give adequate notice to market participants of what activity would constitute fraud, and has not justified the benefits of its resource shuffling proposal against the burdens of complying with such a rule. First, CARB’s decision to define resource shuffling as “fraud” would create a wholly new violation, an action that is not clearly authorized under CARB’s enabling statutes. Agencies are only able to act in the manner prescribed to them by law. Valid administrative action must be within the scope of authority the legislature conferred to the agency, cannot be inconsistent with the agency's authorizing statutes, and must be reasonably necessary to affect the purpose of the applicable statute. Government Code, sections 11342.1, 11342.2; Agnew v. State Bd. of Equalization, 21 Cal.4th 310, 321-22 (1999); County of San Diego v. Bowen, 166 Cal.App.4th 501, 508 (Cal.App.4.Dist 2008); In re J.G., 159 Cal.App.4th 1056, 1066-67 (Cal.App.3 Dist. 2008). To the extent any departmental action exceeds the power delegated by the Legislature, the action is void. Kaiser Foundation Health Plan, Inc. v. Zingale, 99 Cal.App.4th 1018, 1027 (Cal.App.3.Dist. 2002). By proposing to make resource shuffling a violation of the cap and trade regulation and a form of fraud, CARB arguably would expand its power beyond that which is statutorily supported. Although CARB has cited to a number of sections in the Health and Safety Code as offering authority for its proposed language, including sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, none of the enumerated sections, nor any other section of the Health and Safety Code, provide any basis by which CARB can designate an action to be fraud or otherwise create a new violation and penalty. With these provisions, the Legislature empowered CARB to create a program to regulate greenhouse gas emissions, which includes setting standards regarding emissions, monitoring and reporting the resulting emissions. At no point in the Code did the Legislature authorize CARB to expose market participants to new civil or criminal fraud provisions triggered by a failure to adhere to California's emissions program. Reading in such an authorization would not constitute a permissible interpretation of the statute, but rather would amend the statute to broaden the scope of CARB's authority well beyond what the Legislature stated. CARB's proposed fraud language would establish a violation that is not supported by CARB's greenhouse gas authority, and thus should be removed from the final regulations. (MCSG3)

> **Response:** We renumbered the resource shuffling prohibition as new section 95852(b)(2), and we modified the section to delete the characterization of resource shuffling as fraud, rendering moot MCSG3's discussion of fraud in this comment.

I-59. Comment: In the 15-day changes document at section 95852(b)(1), CARB includes a provision against resource shuffling associated with out-of-state energy generation. Such resource shuffling is treated as a fraudulent action and may carry significant penalties. EDF agrees that resource shuffling may be a serious concern for California, both for out-of-state electricity and for natural gas (Phase II). If regulated entities are allowed to take actions that reduce compliance obligations in California and those actions are the sole result of shifting where the electricity is delivered, (without a change to the Western Interconnected Grid resource mix), the overall reductions achieved by the program may be compromised. Of course, the use of anti-shuffling provisions should be counterbalanced by the complexity it adds to the program and CARB's ability to monitor and enforce it. CARB must also evaluate, to the extent it has not already done so, the ability of this provision to affect electricity generation balancing and delivery in the Western Interconnected Grid and potential disincentives for in-state entities to divest long-term contracts with high-emitting energy generation. EDF recommends CARB release additional explanatory information, prior to rule adoption, specifying the types of activities covered (with hypothetical examples), how it would be enforced, and the level of oversight that is likely to be needed. Such information would be valuable for reducing the need for enforcement if it clears up ambiguities that exist among covered entities and would provide more public confidence about the operations of this new provision. (EDF4)

> **Response:** We modified the resource shuffling prohibition section (now new section 95852(b)(2)), and the definition of resource shuffling in section 95802(a). We will monitor and analyze electricity data reported pursuant to the MRR to determine if there is evidence of activity among covered entities that suggest that further consideration of the prohibition and attestations is necessary. In addition to making these modifications and monitoring electricity market data, we plan to work with stakeholders after the regulation is considered by the Board to ensure that stakeholders clearly understand the resource shuffling provisions, and to ensure there are not disincentives for in-state utilities or other entities to divest themselves of ownership or contracts for high-emitting generation.

I-60. Comment: Additionally, we suggest that entities be allowed to submit their attestations electronically in conjunction with annual emissions data reports. Modify section 95852(b)(1) as follows:

> (1) Resource shuffling is prohibited, is a violation of this article and is a form of fraud. ARB will not accept a claim that emissions attributed to electricity delivered to the California grid are at or below the default emissions factor for unspecified electricity specified pursuant to MRR section 95111 if that delivery involves resource shuffling. The following attestations must be submitted to ARB annually in writing, by certified mail ~~only~~ or electronically in conjunction with the annual emissions data report:
>
> > (A) "I certify under penalty of perjury of the laws of the State of California that [facility or company name] has not intentionally engaged in the activity of resource shuffling to reduce compliance obligation for emissions, ~~based on emission reductions that have not occurred~~. (WPTF2)

> **Response:** We disagree. A written attestation is required to ensure that each facility specifically acknowledges its obligations and actions. A "check the box" attestation would be insufficient for this purpose. Furthermore, by defining resource shuffling as "any plan, scheme, or artifice...." it is clear that intent is a necessary condition for an activity to meet the definition.

I-61. (multiple comments)
Comment: LADWP is concerned that this resource shuffling provision may create a disincentive for an early transition away from coal. LADWP requests that ARB study the issue further to determine the best approach. The inclusion of the resource shuffling provisions can impede LADWP's aggressive efforts to make an early transition away from coal. It is unclear from this resource shuffling provision how LADWP or other electricity importers with long-term take-or-pay power contracts for out-of-state coal generation are expected to undertake the expensive transition away from those

resources without a full recognition by ARB that such actions constitute emission reduction benefits for California's ratepayers. LADWP is not positioned to shut down or retire the out-of-state coal generation in which it has only a limited ownership interest, but it can take early action to reduce demand for this type of generation by investing in and procuring cleaner replacement power. The potential outcome would be to penalize LADWP for early coal divestiture. LADWP requests clarification in section 95802(a)(245)(B) that early action to divest of coal prior to when the Emissions Performance Standard (EPS) requires compliance would not be treated as resource shuffling. Without that clarification, the Regulation could be interpreted such that LADWP's early divestiture of Navajo Generating Station (Navajo) prior to 2019 may be considered resource shuffling. (LADWP4)

Comment: The resource shuffling provision is a new concept that should be further vetted. There are potential unintended consequences that may create a disincentive for early coal divestiture. LADWP requests that the ARB study this issue further to determine the best approach that would provide the appropriate incentives for early action, avoid legal infirmities, and ensure continued reliability of the electrical grid. Modify section 95802(a)(245) as follows:

> ~~(245) "Resource Shuffling" means any plan, scheme, or artifice to receive credit based on emissions reductions that have not occurred, involving the delivery of electricity to the California grid, for which:~~
> ~~(A) An emission factor below the default emission factor is reported pursuant to MRR for a generation source that has not historically served California load (excluding new or expanded capacity). And, during the same interval(s), electricity with higher emissions was delivered to serve load located outside California and in a jurisdiction that is not linked with California's Cap-and-Trade Program; or~~
> ~~(B) The default emission factor or a lower emissions factor is reported pursuant to MRR, for electricity that replaces electricity with an emissions factor higher than the default emission factor that previously served load in California; except when the replaced electricity no longer serves California load as a result of compliance with the Emission Performance Standards adopted by the California Energy Commission and the California Public Utilities Commission pursuant to Senate Bill 1368 (Perata, Chapter 598, Statutes of 2006).~~ (LADWP4)
>
> **Response:** Because resource shuffling could result in significant leakage, we did not delete the definition. However, we deleted paragraphs (A) and (B). We agree with LADWP that early action to reduce emissions is not resource shuffling. We modified section 95802(a)(245)(B) in part to meet this concern.

I-62. (multiple comments)
Comment: The resource shuffling attestations in section 95852(b)(1)(A) place the burden of proof on an individual person representing a first deliverer that is unreasonable, and for which compliance would be impossible, especially for a large utility. The attestations should be deleted. No individual person would have the full

knowledge required to know that the entity he or she represents did not engage in resource shuffling for each and every power transaction. For LADWP, there are approximately 1,000 NERC E-tags that are generated per day for scheduling electricity in and out of LADWP's Balancing Authority area. When combined with the account representative attestation, the annual resource shuffling attestations could be interpreted to apply personal penalties, including the possibility of fine or imprisonment. This is not workable. Modify section 95852(b)(1) as follows:

> ~~(1) Resource shuffling is prohibited, is a violation of this article and is a form of fraud. ARB will not accept a claim that emissions attributed to electricity delivered to the California grid are at or below the default emissions factor if that delivery involves resource shuffling. The following attestations must be submitted to ARB annually in writing, by certified mail only:~~
>
> > ~~(A) "I certify under penalty of perjury of the laws of the State of California that [facility or company name] has not engaged in the activity of resource shuffling to reduce compliance obligation for emissions, based on emission reductions that have not occurred."~~
> > ~~(B) "I understand I am participating in the Cap-and-Trade Program under title 17, California Code of Regulations, article 5, and by doing so, I am now subject to all regulatory requirements and enforcement mechanisms of this program and subject myself to the jurisdiction of California as the exclusive venue to resolve."~~ (LADWP4)

Comment: The certifications that are required by section 95852(b)(1) should be modified to recognize that the signatory, an individual, is certifying as agent for the covered entity and to avoid the absurdity of requiring the signatory to certify that the signatory himself or herself is participating in the cap-and-trade program. These certifications are not strictly necessary because certifications are required under the MRR for the whole of an entity's emissions report, as well as independent verification. Modify section 95852(b)(1) as follows:

> (1) Resource shuffling is prohibited, and is a violation of this article~~ and is a form of fraud~~. ARB will not accept a claim that emissions attributed to electricity delivered to the California grid are at or below the default emissions factor for unspecified electricity specified pursuant to MRR section 95111 if that delivery involves resource shuffling. The following attestations must be submitted to ARB annually in writing, by certified mail only:
>
> > (A) "I certify under penalty of perjury of the laws of the State of California that [facility or company name], for which I am an agent, has not knowingly engaged in the activity of resource shuffling to reduce compliance obligation for emissions, based on emission reductions that have not occurred."
> > (B) "I understand [facility or company name], for which I am an agent, is~~I am~~ participating in the Cap-and-Trade Program under title 17, California Code of Regulations, article 5, and by doing so, it is~~I am~~ now subject to all regulatory requirements and enforcement mechanisms of this program

> and subjects it~~my~~self to the jurisdiction of California as the exclusive venue to resolve disputes."

The Southern California Public Power Authority (SCPPA) recommends that the resource shuffling provisions in section 95802(a)(245) and section 95852(b)(1) be temporarily removed for further evaluation or, at minimum, revised. The complex issues that are raised by the new resource shuffling provisions cannot be fully assessed in the time allowed for "15-day" comments, even given that the concepts were broached in a "discussion draft" of the Regulation that was released on July 7, 2011, ("Discussion Draft"). Thus, SCPPA recommends that the resource shuffling provisions be temporarily removed from the Regulation until the full ramifications of the provisions can be evaluated. (SCPPA6)

> **Response:** We revised section 95852(b)(1) (now renumbered as (b)(2)) as requested, except that we did not add the word "knowingly" in paragraph A. Because resource shuffling is defined as a "plan, scheme, or artifice" we do not believe that a facility or company can unknowingly shuffle resources. We revised section 95802(a)(245) (now (a)(251)) to meet stakeholder concerns. We did not temporarily remove the resource shuffling provisions because these provisions are necessary to minimize leakage. While we did not delete the attestation requirements for the reasons discussed in a previous response, we modified the attestations based on SCPPA6's recommendation. New sections 95852(b)(2)(A and B) make it clear that the person making the attestation is doing so as an agent of the facility or company that is the first deliverer. We believe this modification should meet the commenter's concern.

I-63. (multiple comments)
Comment: LADWP urges ARB to temporarily remove resource shuffling provisions in sections 95802(a)(245) and 95852(b)(1) and seek public comment as part of a new 45-day comment period. It appears that resource shuffling is a provision that has been added for the first time to the Cap and Trade Regulation as part of the 15-Day Modified Text. LADWP is concerned that this resource shuffling provision needs to be further vetted with stakeholders in order to have a collective understanding of how it would be implemented. Vetting would also help to identify any potential unintended consequences. The inclusion of the resource shuffling provision does not necessarily coincide with the normal and emergency operations of the grid required by Federal Energy Regulatory Commission (FERC) reliability standards. From an operational perspective, it is unclear how a first deliverer would know in advance if and when it was engaged in resource shuffling.

California is one of fourteen Western states along with the provinces of Alberta and British Columbia and the northern portion of Baja California, Mexico that make up the Western Interconnection. The priority for grid operators is, first and foremost, coordinating and promoting bulk electric system reliability to avoid costly regional power outages that risk life and property. There are thousands of transactions that involve millions of North American Reliability Corporation (NERC) E-tags for movement of electricity in and out of California on an annual basis. Those transactions do not include consideration of the emissions attribute of electrons that are imported into California for the purposes of identifying resource shuffling.

Additionally, the resource shuffling provision does not take into consideration power emergencies. LADWP and other California EDUs have agreements with the Western Electricity Coordinating Council (WECC) to support other utilities within the Western interconnection in emergency situations to keep the electrical grid operating smoothly. Conversely, the practice of mutual assistance ensures that California EDUs may also receive assistance from utilities outside California in cases of emergency outages (fires, earthquakes, storms, heat waves). The resource shuffling provision does not appear to take into account the existing WECC agreements for mutual assistance and would impose heavy penalties on first deliverers. This approach would have the unintended consequence of compromising the reliability of the overall interstate grid. (LADWP4)

Comment: The definition of resource shuffling should be revised to exclude situations where a covered entity either unknowingly engages in activities that resemble resource shuffling, or adjusts its portfolio for valid economic dispatch reasons. Modify section 95802(a)(245) as follows:

> (245) “Resource Shuffling” means any intentional plan, scheme, or artifice to receive credit based on emissions reductions that have not occurred, involving the delivery of electricity to the California grid, for which:
>
> (A) An emission factor below the default emission factor is reported pursuant to MRR76 for a generation source that has not historically served California load (excluding new or expanded capacity and grandfathered contracts). New or expanded capacity is relative to capacity as of 01/01//2012. And, during the same interval(s), the same entity reporting the lower emissions delivers electricity with higher emissions ~~was delivered~~ to serve load located outside California and in a jurisdiction that is not linked with California’s Cap and Trade Program; or
>
> (B) The default emission factor or a lower emissions factor is reported pursuant to MRR, for electricity that replaces electricity with an emissions factor higher than the default emission factor that ~~previously~~ served load in California prior to 01/01/2012; except when:
> (1) the replaced electricity no longer serves California load as a result of compliance with the Emission Performance Standards
> (2) the contract with the resource was terminated prior to 01/01/2012. (SCE3)

Response: We did not remove the resource shuffling provisions because, as shown by several of the comments, resource shuffling can introduce significant leakage. Furthermore, the Board directed staff to address resource shuffling in Board Resolution 10-42: “BE IT FURTHER RESOLVED that staff will further develop requirements to ensure changes in reported emissions from imported electricity that serves California does not result merely in a shift of emissions within the Western Electricity Coordinating Council region, but reduces overall emissions." We believe that a prohibition on resource shuffling is necessary to preserve the environmental integrity of the regulation. The commenter appears to be concerned that common electricity transactions, which entities engage in with no intent to shuffle resources, could be considered resource shuffling. Normal transactions that result in unintended or unknowable changes in emissions levels that are not part of a "plan, scheme, or artifice to receive credit based on emissions reductions that have not occurred" are not resource shuffling as defined. In power emergencies, first deliverers may redirect electricity as needed for reliability. These kinds of changes are not resource shuffling as defined.

SCE3 suggested changes to the definition for Resource Shuffling. SCE3 states that the definition should be revised to "exclude situations where a covered entity either unknowingly engages in activities that resemble resource shuffling, or adjusts its portfolio for valid economic dispatch reasons." Although we do not agree with the specific changes that SCE suggested, we did modify the definition, and believe the changes we made will provide the same result as SCE's suggestion. In Section 95802(a), ARB revised the definition of "Resource Shuffling." We removed the term "fraud" and deleted language that might capture situations where the delivery of electricity is a result of legitimate and typical transactions due to economic reasons, or where there is no actual intent to circumvent this regulation.

In addition, in Resolution 11-32 the Board directed the Executive Officer to continue discussions with stakeholders to identify and propose, as necessary, during the initial implementation of the cap-and-trade program, potential amendments to the Regulation on the definition of Resource Shuffling to:
(a) provide appropriate incentives for accelerated divestiture of high-emitting resources by recognizing that these divestitures can further the goals of AB 32, and (b) ensure that changes in reported emissions from imported electricity that serves California do not result merely in a shift of emissions within the Western Electricity Coordinating Council region, but instead reduces overall emissions.

Legal

I-64. (multiple comments)
Comment: The definition of "Resource Shuffling" must be changed to avoid significant unintended consequences to the regional wholesale markets. PacifiCorp, as a MJRP, is regulated by six different state regulatory commissions and is equally subject to each state commission's laws and rulings. PacifiCorp operates in all six states under a Multi-State Process (MSP) utilized to allocate costs across the six state jurisdictions as well as to share the PacifiCorp system benefits across the six states. If resource attribution is changed within the MSP protocol, it could result in resources being delivered to California that have "not historically served California load," thus triggering the Resource

Shuffling provisions. PacifiCorp is concerned that by continuing to follow the orders of its six state utility commissions, the proposed ARB Regulation has the ability to include this required change as an allegation of criminal behavior. Further, maintaining normal system reliability functions, such as providing operating reserves and balancing services, which are typically from baseload resources, could result in an allegation of criminal behavior under the current Resource Shuffling prohibition. PacifiCorp does not believe it is ARB's intent to criminalize what are legitimate market and system operations behaviors. Therefore, PacifiCorp strongly recommends striking the language that refers to Resource Shuffling as fraud. Resource Shuffling should be subject to the same penalty and enforcement provisions as all the other prohibitions and requirements of the Regulation, and not singled out, especially in a vague manner with a significant possibility of unintended consequences. Further, PacifiCorp recommends explicit exclusions from the definition of Resource Shuffling for resource decisions made as part of a utility commission decision, for system maintenance and reliability decisions, and in reaction to force majeure events. Resource Shuffling does not exist when a utility allocates resources to a particular service territory pursuant to a decision of the California Public Utilities Commission or a regulatory commission of another state, for system maintenance and reliability decisions, or in reaction to force majeure events. Modify section 95852(b)(1) as follows:

> (1) Resource shuffling is prohibited and is a violation of this article. ~~and is a form of fraud.~~ ARB will not accept a claim that emissions attributed to electricity delivered to the California grid are at or below the default emissions factor for unspecified electricity specified pursuant to MRR section 95111 if that delivery involves resource shuffling, unless the resource has been registered as a specified import. The following attestations must be submitted to ARB annually in writing, by certified mail only:
>
> > (A) "I certify under penalty of perjury of the laws of the State of California that [facility or company name] has not intentionally engaged in the activity of resource shuffling to reduce compliance obligation for emissions, based on emission reductions that have not occurred.
>
> (B) "I understand I am participating in the Cap-and-Trade Program under title 17, California Code of Regulations, Article 5, and by doing so, I am now subject to all regulatory requirements and enforcement mechanisms of this program and subject myself to the jurisdiction of California as provided in title 17, California Code of Regulations, article 5, as the exclusive venue to resolve dispute brought pursuant to this Article.

(PACIFICOR3)

Comment: The concept of "resource shuffling," as defined in section 95802(245) of the Cap and Trade regulation, is so broad it would encompass and impede routine business activity taken by energy companies based on legitimate economic considerations and penalize individuals for actions that are outside of their knowledge or control. In the commercial world, energy portfolios are consistently updated and rebalanced for economic reasons. However, under the proposed regulation, reshuffling a portfolio as contracts expire in order to reflect new economic realities could conceivably constitute resource shuffling.

In another example, the proposed prohibition against resource shuffling could arguably require companies to understand the full sales history of each facility generating electricity and certify the use of that electricity when transacting. Ascertaining the entire providence of each resource is impracticable, and places an unduly high burden to investigate on commercial activity, especially when one considers the number of transactions routinely completed to serve load in California.

Does CARB expect a market participant importing power into California to undertake such a review with every trade? Would a market participant be subject to allegations of fraud if it conducted this research periodically rather than with each trade? Would market participants be liable for fraud if they relied on generator representations? If there were a violation for fraud, would charges be brought against an individual trader and/or an entire company? What types of penalties might apply? Would a counterparty to a trade be liable if a generator mischaracterized to the counterparty or CARB where it sent its power or the applicable emission factors reported? These examples highlight that CARB's proposed resource shuffling language does not meet the basic notice requirements because it fails to provide any real details as to how a company or individual may or may not act or how the rule will be enforced.

Moreover, the suggested language is indefinite and confusing in a highly significant way. It offers no guidance as to either the type of fraud, criminal or civil, that resource shuffling would constitute or the resulting consequences of a violation. These failures conflict with the requirement to provide adequate notice, which figures prominently in establishing the validity of civil and criminal regulations. In the criminal context, a regulation will be held unconstitutionally vague if it fails to give a person of ordinary intelligence a reasonable opportunity to know what is prohibited, so that he may act accordingly. Similarly, a regulation must provide sufficiently definite standards of application to prevent arbitrary and discriminatory enforcement.

CARB's creation of a fraud penalty arguably fails these notice tests. It neither gives a covered entity a reasonable opportunity to know what is prohibited nor provides definite standards of application. The lack of specificity in CARB's proposed language creates ambiguity as to what would constitute resource shuffling, while also leaving open the possibility that criminal sanctions would result from a violation. Even if the regulation proposes civil rather than criminal liability, notice remains a critical component of the administrative rulemaking process. Economic and civil regulations may be subject to a less strict vagueness test than criminal regulations; however, the criminal test is still informative. This is particularly true because the proposed cap and trade regulation characterizes resource shuffling as a form of fraud with unknown but potentially stringent consequences. As such, a civil fraud violation could be considered quasi-criminal in nature, warranting a relatively strict vagueness test. Even if the regulation is merely civil in nature, notice remains critical to the civil administrative process for rulemaking in California. Individuals must have notice as to what a regulation commands and prohibits.

Yet CARB's proposed language with respect to resource shuffling would make it difficult to pinpoint whether any specific conduct clearly falls within its definition. Moreover, no common knowledge or understanding exists within the energy community about what constitutes resource shuffling. Cranston, 40 Cal. 3d at 764. As such, even under a weaker notice standard, the Board's regulation is vague enough to limit the ability of a company or individual to reasonably understand its limits, and, as a result, the language violates due process. Finally, the proposed resource shuffling language poses a number of additional burdens on market participants without clear benefit.

For instance, as currently written, the regulation arguably could require a resource owner to continue to use its resource in a specific manner going forward based on how that resource was used in the past, regardless of whether that use was to source electricity in California or not. This is not only an unconstitutional restraint of inter-state commerce, but it also places an unreasonably high burden on business to have to ascertain the providence of the resource. Performing such diligence would be difficult, and it is unclear that the proper historical information even exists to verify compliance with such a limitation. For example, how far back would market participants have to go to ascertain a resource's past use? Would every wholesale and retail sale have to be evaluated? Would NERC tags have to be used to verify flow? What about for sales before NERC tagging was required? Would any due diligence requirement apply equally to spot and long-term contracts? What repercussions would there be if a plant responds to a reliability instruction from a balancing authority that forces the plant to diverge from its past use? The sparse resource shuffling language currently proposed leaves too many questions open. CARB's proposed language also does not accomplish its apparent aim.

CARB seems to be attempting to regulate trading to prevent individuals from purposely circumventing the cap-and-trade emissions requirements in California by shifting the accounting for emissions outside the region. However, without objective guidance on how the agency will determine the intent behind an action that might have attributes that look like shuffling, the current regulation could unreasonably burden legal conduct. Indeed, a large swath of potential trading activity could conceivably fall within the scope of resource shuffling, and yet the proposed regulation is not adequately tailored to distinguish between activities where the involved parties did not intend to circumvent the regulations but rather are merely reacting to, and contracting to address, economic realities. In such situations, where the intent of traders is to act efficiently and economically in the market, they should not be subject to even a threat of penalties for resource shuffling.

The legal issues highlighted above indicate that CARB needs to strike the shuffling provision. If CARB continues to believe that resource shuffling is an issue and can demonstrate that it has legal authority to address it, including as to out-of-state resources, CARB should revise and re-propose the resource shuffling regulation to more clearly meet the Board's aims and to provide those subject to the rule with more clarity on the requirements. (MSCG3)

Response: We are familiar with the complex regulatory regime under which PacifiCorp operates, and we understand that the MSP process could result in changes in resource attribution as a result of an agreement between the six state commissions. We believe that changes in resource decisions made for system maintenance and reliability or in reaction to force majeure would not be a plan, scheme, or artifice to receive credit based on emission reductions that have not occurred. While it is theoretically possible for a utility commission to be part of a resource shuffling plan, scheme, or artifice, we consider such an event to be extremely improbable. We believe that the modifications made to the regulation should meet PacifiCorp's concern.

MSCG3 believes that the resource shuffling provisions are too broad, and states that under the provisions "reshuffling a portfolio as contracts expire in order to reflect new economic realities could conceivably constitute resource shuffling." We agree, but only insofar as such reshuffling falls within the regulatory definition of resource shuffling. We do not agree that the regulation would "require companies to understand the full sales history of each facility generating electricity and certify the use of that electricity when transacting." We believe that a party should know the immediate provenance of its resources (whether unspecified or specified) used to supply power for import to California. A party need not know where unspecified power purchased on the market comes from.

MSCG3's third paragraph asks many rhetorical questions. Some are now moot because we removed reference to fraud, and others are now moot to the extent that parties understand the legal meaning of "plan, scheme, or artifice."

Most of MSCG3's fourth to seventh paragraphs are moot, because we have removed the reference to fraud in the regulation. MSCG3 asserts that the prohibited conduct in the regulation is unconstitutionally indefinite. We note that the regulation is not creating a criminal offense. The regulation does clearly specify that resource shuffling is a particular plan, scheme, or artifice to receive credit based on emissions reductions that have not occurred. It does not specify in any way the manner in which a resource owner should use that resource, and therefore does not restrain interstate trade, as MSCG has asserted. There is also clear benefit to the burdens on the market created by our attempt to ensure that GHG emission reductions induced by this regulation are real.

We did not strike the resource shuffling provisions, as recommended in the last paragraph of the comment. However, we plan to continue to engage with stakeholders on this issue, to clarify the meaning and intent of the final regulatory languages. If, while engaging with stakeholders there are significant unintended consequences or problems with our current approach, staff will recommend to the Board ways to prevent them, including possible new rulemaking to further modify the regulation.

I-65. Comment: Section 95852 prohibits "resource shuffling." While LS Power agrees with the general goal of discouraging importers from misrepresenting their GHG emissions, in practice, the resource shuffling provisions are impractical. There are many instances in wholesale markets where a purchasing entity will not know where its power will be coming from. In addition, the regulation applies to all regulated entities, when there are clearly entities that have not engaged in resource shuffling. Specifically, the regulations should allow for an upfront determination that a specified importer is not engaged in resource shuffling where CARB has issued a specified emissions factor for a particular facility that is applied to output sold into the CAISO or other California markets. (LS Power)

Response: We appreciate the commenter's agreement with the goal of discouraging the misrepresentation of GHG emissions, but disagree that resource shuffling provisions, as modified, are impractical. It is true that a purchasing entity does not know "where its power will be coming from" when it is from unspecified sources. But some resource shuffling can involve substituting unspecified power for power from high-emission facilities. Even if an importer delivers electricity into California from a source for which ARB has issued a specified emissions factor, it is possible to use such electricity in a plan, scheme, or artifice to shuffle resources, and we believe such activity must be prohibited.

I-66. Comment: The relationship between the Cap and Trade Rule's definition of "resource shuffling" and section 95111(g)(4) of the Mandatory Reporting Rule is unclear. Reading the Cap and Trade Rule's proposed definition of resource shuffling in conjunction with the proposed modifications to the MRR, it appears that ARB may have intended to narrow what constitutes resource shuffling activities via the proposed changes to MRR section 95111(g)(4). That section, describing five categories of "specified sources," parallels subsection (A) of the Cap and Trade Rule's resource shuffling definition by differentiating sources of electricity historically consumed in California from new sources of electricity and existing sources with additional capacity (sections 95111(g)(4)(A), 95111(g)(4)(D), and 95111(g)(4)(E). If ARB intended to reference all or any part of MRR section 95111(g)(4) as sources and activities excluded from the Cap and Trade Rule's definition of resource shuffling, then Powerex requests that this be clarified by making the reference explicit. (POWEREX)

Response: The MRR requires first deliverers to report whether delivered electricity from a specified source falls into a category that is clearly not likely to be resource shuffling. However, we are aware of other circumstances in which electricity that does not fall into one of the categories could be part of a plan, scheme, or artifice that intentionally resulted in resource shuffling. We believe that the prohibition of resource shuffling stands effectively without reference to MRR section 95111(g)(4).

I-67. Comment: The definition of Resource Shuffling implies a requirement of intent, but its usage in this section suggests that it could apply more broadly, resulting in an inadvertent violation of the regulation. For this reason, further discussion and clarification of Resource Shuffling is required. (PGE4)

> **Response:** The specific language of the definition requires a plan, scheme, or artifice, meaning that there is no inadvertent resource shuffling. We removed additional language from the definitions that might have been ambiguous as to the breadth of the definition.

I-68. Comment: In the course of serving its load at lowest cost, an in-state utility may carry out a transaction known as a "wheel-through" in which electricity is imported into the California Independent System Operator "CAISO" Control Area at one import location and concurrently exported outside of the Control Area at another export location in the same hour of delivery. In this case, it is assumed that the utility would claim zero compliance obligation if the amount imported and exported were the same. However, it is also possible for an in-state utility to carry out two 25 MW import transactions for a given hour at Location A and only one 25 MW export at Location B in that same hour. If one of the 25 MW imports was from a renewable resource with a zero compliance obligation, and the other 25 MW import was from a natural gas resource, which of these two imports would the utility be required to assign to the 25 MW export for the wheel-through? Under current business practices, it makes no difference and either resource may be paired with the import. From an economic perspective under ARB's proposed regulations, it would make sense for the utility to define the wheel-through based on the natural gas resource in order to have no compliance obligation for the transaction. However, it is unclear if under the current Regulation this could be considered to be Resource Shuffling by specifying the natural gas resource for the wheel-through transaction rather than the renewable resource, although either would be a permissible business practice. (PGE4)

> **Response:** The MRR defines "electricity wheeled through California" in part as follows: "'Electricity wheeled through California' is documented on a single NERC e-Tag showing the first point of receipt located outside the State of California, an intermediate point of delivery located inside the State of California, and the final point of delivery located outside the State of California." With this precise definition, we can identify which, if any, of the two 25 MW imports is wheeled. PG&E does not provide sufficient information to determine if there is a wheel in this case. The MRR contains the reporting requirement for wheels, imports, and exports. Furthermore, this regulation allows for a QE adjustment for qualified exports. The export transaction may be used in the calculation of the QE adjustment pursuant to section 95852(b) as modified. If an electricity importer reports correctly pursuant to the MRR as modified, and has no intent to participate in a plan, scheme, or artifice to receive undue credit for GHG emissions reductions, there will be no resource shuffling.

I-69. Comment: The Utilities agree that an intentional act to commit resource shuffling purely to game the Cap and Trade market and avoid an emissions obligation should be discouraged. There are numerous provisions in statute that either prohibit the delivery of high emitting GHG resources (SB 1368) or encourage the delivery of zero emitting GHG resources (SBx12). Thus, it is unnecessary to include sections 95802(a)(245)(A) and (B), and the Utilities recommend their deletion. Further, the term “interval” is undefined and could lead to an unnecessary penalty determination. Due to transmission constraints, curtailments, and the general nature of power trading, there can be times when a higher emissions resource is sold off in place of a lower emissions resource. These activities can be “historical”, or done on a real-time basis. The Utilities additionally recommend this concept be further explored through a series of workshops and discussions. Modify section 95802(a)(245) as follows:

> (245) “Resource Shuffling” means any intentional plan, or scheme, ~~or artifice~~ to receive credit based on emissions reductions that have not occurred~~.~~, ~~involving the delivery of electricity to the California grid, for which:~~
>
> ~~(A) An emission factor below the default emission factor is reported pursuant to MRR for a generation source that has not historically served California load (excluding new or expanded capacity). And, during the same interval(s), electricity with higher emissions was delivered to serve load located outside California and in a jurisdiction that is not linked with California’s Cap-and-Trade Program; or~~
> ~~(B) The default emission factor or a lower emissions factor is reported pursuant to MRR, for electricity that replaces electricity with an emissions factor higher than the default emission factor that previously served load in California; except when the replaced electricity no longer serves California load as a result of compliance with the Emission Performance Standards adopted by the California Energy Commission and the California Public Utilities Commission pursuant to Senate Bill 1368 (Perata, Chapter 598, Statutes of 2006).~~
>
> Modify section 95852(b)(1) (1) Resource shuffling is prohibited, is a violation of this article and is a form of fraud. ~~ARB will not accept a claim that emissions attributed to electricity delivered to the California grid are at or below the default emissions factor for unspecified electricity specified pursuant to MRR July 2011 section 95111 if that delivery involves resource shuffling. The following attestations must be submitted to ARB annually in writing, by certified mail only.~~ (MID3)

Response: We deleted sections 95802(a)(245)(A) and (B) as recommended, but we did not delete the words “or artifice,” as no reason has been proposed to do so. The resource shuffling sections as modified will not prohibit standard and existing electric transactions that are not part of a resource shuffling plan, scheme, or artifice. As requested by the commenters, we held a workshop August 26, 2011, in which resource shuffling and other issues concerning imported electricity were vetted. We have no intent to prohibit legitimate transactions that do not involve resource shuffling. We appreciate the commenter's recognition of the need to prohibit resource shuffling.

While we deleted the second sentence of section 95852(b)(1) as requested by MID3, we did not delete the requirement for attestations, for reasons explained in other responses.

Finally, we understand that the commenters and other stakeholders continue to have concerns about resource shuffling. We are committed to continuing to monitor and analyze reported data to determine whether there is evidence that further consideration should be given to these requirements. We plan to continue listening to stakeholder concerns about these provisions, and if we determine that the regulations provisions are not fully adequate based on new information provided, or based on observed changes in the market, we will ask the Board to consider modifying the regulation.

Replacement Electricity

I-70. (multiple comments)
Comment: The definition of "Replacement Electricity" restricts the ability to use replacement electricity in connection with out-of-state resources that are "Variable Renewable Resources." As written, this definition appears to exclude all non-variable renewable resources, such as biomass facilities, that may be procured from out-of-state resources in order to meet the RPS. Excluding these resources from the ability to utilize the replacement electricity provisions of the Regulation will mean that these out-of-state resources will have to meet a more stringent and costly delivery requirement under the RPS in order to avoid incurring GHG emission reduction costs on electricity purchases that would otherwise qualify for a zero emission rate, creating an unnecessary and unwarranted "value" arbitrage for out-of-state resources. To remedy this problem, the ability to claim the zero emissions rate for replacement electricity should be applicable to all out-of-state renewable resources that are used to meet the RPS. The reference to "variable" should be deleted from the definition. (CNE)

Comment: The definition of "Replacement Electricity" restricts Replacement Electricity to being energy that replaces renewable energy that meets the narrow definition of "Variable Renewable Resources," which excludes many sources of renewable energy such as small hydroelectric projects at impoundments, geothermal projects, biomass projects, and biogas combustion. The production of renewable energy from those excluded sources may vary over time even though the sources may not be traditionally classified as variable or intermittent. Although those excluded renewable resources may have relatively stable output given current technologies, the purchaser may need to obtain replacement energy to accommodate transmission constraints or to shape the renewable energy, for example, to meet seasonal load requirements. Thus, the definition of "Replacement Electricity" should be broadened by deleting the word "variable" from the definition and severing any tie to the restrictive definition of "Variable Renewable Resources" in section 95802(a)(272). (SCPPA6)

Comment: NCPA, in addition to several other entities, including the Joint Utilities, has proposed that the definition of replacement electricity in section 95802(a) be revised to strike the last sentence constraining the location of the resources and the reference to variable resources. Replacement electricity, as that definition is proposed to be revised, is an important tool associated with renewable generation arrangements. This tool, however, should not necessarily be restricted to “variable” resources. The provisions of this section should also be revised to acknowledge the broader range of ownership arrangements utilized in these kinds of transactions (as the Legislature did in Senate Bill X1 2). Modify section 95852(b)(3) as follows:

> (3) Replacement electricity that substitutes for electricity from a <u>variable</u> renewable resource qualifies for the ARB facility specific emission factor specified pursuant to MRR section 95111 of the <u>variable</u> renewable resource under the following conditions:
>
> > (A) First deliverers of replacement electricity have a contract, or ownership relationship, with the supplier of the replacement electricity, in addition to a contract <u>or ownership rights to electricity generated by</u> with the variable renewable resource; and (NCPA3)

Comment: LADWP recommends that ARB not limit this provision to replacement electricity for variable renewables only. Modify section 95852(b)(3) as follows:

> (3) Replacement electricity that substitutes for electricity from a ~~variable~~ renewable resource qualifies for the ARB facility specific emission factor specified pursuant to MRR section 95111 of the ~~variable~~ renewable resource under the following conditions:
>
> > (A) First deliverers of replacement electricity have a contract, or ownership relationship, with the supplier of the replacement electricity, in addition to a contract with <u>a supplier of</u> the variable renewable resource; and
> >
> > (B) The amount of the reported replacement electricity does not exceed the amount for the reported annual ~~variable~~ renewable resource. (LADWP4)

Comment: Section 95852(b)(3)(A), requiring first deliverers of replacement electricity to have a contract or an ownership relationship with the supplier of the replacement electricity, is confusing and may be unnecessary. Nearly all commercial transactions involve a contract; even electricity transactions conducted over the telephone are done so with an underlying enabling agreement. SCE urges ARB to clarify what would constitute a contract in order to satisfy this requirement or delete the requirement entirely. To clarify the term “contract,” SCE recommends that ARB allow for considerable flexibility in defining “firming and shaping” contracts. If an entity must have a “long-term” contract with the supplier of the replacement electricity, this would effectively require entities such as SCE to outsource the firming and shaping of out of state renewables to third-party service providers at a sizable cost. Because it is typically more efficient and cost-effective for SCE to self-manage these activities, SCE currently does so for its out-of-state renewable generation. Therefore, ARB’s contractual restriction could significantly increase costs to California electricity customers. SCE recommends that ARB revise its language in order to allow utilities the flexibility to manage out-of-state renewable firming and shaping in the most efficient and cost-effective manner possible, or delete the provision entirely, especially for grandfathered projects. (SCE3)

Comment: The proposed definition of "replacement electricity" reflects a fundamental misunderstanding of the function of firming and shaping and must be modified to reflect the zero net replacement energy result of the firming and shaping function. As proposed, this definition unduly constrains the resources available to compliance entities for firming and shaping their renewable energy contracts for delivery into California. Such practices are not only commonplace with regard to renewable contracts, but contemplated by the Legislature and regulators for purposes of the RPS. However, the proposed restriction would require that replacement electricity be sourced from the same balancing authority of the underlying renewable resource. NCPA supports the deletion of this entire sentence, as do the Joint Utilities, as inclusion of this limited definition negates the efficacy of RPS-eligible contracts, increases Cap and Trade Program compliance costs, and is contrary to the RPS goals of the State, all without meeting any of the AB 32 policy objectives. This attempt to disassociate the RPS-eligible generation resource from the electricity delivered into California creates an additional compliance obligation for covered entities that are first deliverers of electricity, and could further result in confusion regarding the treatment of unbundled renewable energy credits associated with that generation.

Comment: We request that the definition of Replacement Electricity be amended to remove the requirement that the replacement electricity come from a source in the same balancing authority area as the renewable energy being firmed and shaped. That requirement does not advance the goal of reducing greenhouse gas emissions. It would have no discernable effect on the amount of greenhouse gas emitted from sources used to firm and shape variable energy resources. Imposing such a requirement could increase the costs of firming and shaping (F&S) transactions, and thereby increase California electricity rates without providing any benefit to the California ratepayers. (BP2, PGE4)

Comment: CARB should amend the definition of "Replacement Electricity" in sections 95102(a)(336) and 95802(a)(237). The current definition requires that Replacement Electricity must originate in the same BAA as the Variable Renewable Resource it is associated with. Because the demand for renewable resource energy in California exceeds the supply of renewable resources in the State, most load serving entities are obliged to import renewable energy and renewable energy products into California to meet RPS mandates. This necessitates the use of F&S contracts for the procurement of variable renewable resource energy so that a firm product can be delivered to serve the ultimate customer load. Providers of "Replacement Electricity" and the host BAA in the western electricity market use a variety of resources throughout the region. There is no reason why the portfolio of resources eligible to provide "Replacement Electricity" in an F&S deal must be limited to a single BAA. This restricts the options for F&S

contracting, and will result in increased wholesale prices and costs to California retail electric customers without any economic or regulatory justification for this restrictive policy. Noble Solutions is cognizant of CARB's concern about transactions in which a GHG-producing resource "supports" the import of an intermittent zero-emissions renewable resource. However, every MWh of zero-emissions renewable energy, regardless of where it physically sinks, displaces a MWh of energy produced by the least efficient resource in the dispatch stack of the host BAA. It is virtually always a GHG reduction whenever zero-emissions renewable resources are operating. For California to impose a GHG charge on "Replacement Electricity" imported in connection with an F&S arrangement is equivalent to charging a California importer a penalty for reducing GHG emissions in another jurisdiction. (NAES)

Comment: The proposed definition of "replacement electricity" in section 95802(a)(237) and applied in section 95852(b)(3) requires that the first point of receipt on the NERC E-tag for replacement electricity be located in the same Balancing Authority (BA) as the renewable resource. This is a needless complication that serves no purpose in ensuring GHG reductions, facilitating tracking and verification of the renewable resources, or furthering the state's RPS and GHG reduction goals. The proposed definition reflects a fundamental misunderstanding of the function of firming and shaping and must be modified to reflect the zero net replacement energy result of the firming and shaping function.

As drafted, the provisions of section 95802(a)(237) as applied in section 95852(b) severely hinder the ability of compliance entities to meet these dual objectives. M-S-R believes that the proposed definition is not intended to be so restrictive as to negate the economic and environmental value created by entities' RPS contracts that involve renewable resources and firmed and shaped resources located in different balancing authorities, or to rely on E-tags for a purpose for which they were not intended. Maintaining this strict requirement provides no real benefits to the State, and pits two State policies against each other. M-S-R urges CARB to closely review the ramifications of this restriction and delete the entire last sentence of the proposed definition. Modify section 95802(a)(237) as follows:

(237) "Replacement Electricity" means electricity delivered to a first point of delivery in California to replace electricity from ~~variable~~ renewable resources in order to meet hourly load requirements. The electricity generated by the ~~variable~~ renewable energy facility and purchased by the first deliverer is not required to meet direct delivery requirements. ~~The physical location of the variable renewable energy facility busbar and the first point of receipt on the NERC E-tag for the replacement electricity must be located in the same Balancing Authority Area~~. (MSR, IEPA4)

Comment: The definition of "replacement electricity" in section 95802(a)(237) should be modified to remove the word "variable" throughout the definition. Limiting the definition of replacement electricity to association with variable renewable resources is inconsistent with the RPS, which currently allows substitute energy to be associated with renewables whenever there is a need for such energy, regardless of the intermittent or non-intermittent nature of the renewable resource. Using “firming and shaping”, or substitute electricity, to effectively bring the energy from renewables into California and use the transmission network most efficiently to do so is most often needed for intermittent resources such as wind power. However, there are circumstances where the underlying electricity from a baseload resource cannot always or easily be transmitted directly from the source into California, and substitute energy is used in those cases for compliance with the RPS. There is no reason why this kind of “firming”—using substitute energy to bring firm baseload power to the State, should not be considered to have zero or reduced GHG for the associated energy delivered, as the action is functionally equivalent to the firming and shaping necessary for intermittent resources. With the removal of the word “variable” in the definition of Replacement Electricity, there is no longer a need for a definition of “Variable Renewable Resource.” Even if there were yet a need for the definition, it is restrictive in mentioning just three renewable resources—wind, solar, and run-of-the-river hydro. Other renewable resources may be considered variable at times. The definition should simply be stricken. (SMUD3)

Comment: Remove restriction to “variable” resources of zero or reduced GHG treatment of replacement electricity. There should be no restriction in the regulations of associating the emission factor of the underlying renewable resource solely to cases involving variable renewable resources. Modify sections 95852(b)(3) and 95852(b)(4) as follows:

> (3) Replacement electricity that substitutes for electricity from a ~~variable~~ renewable resource qualifies for the ARB facility specific emission factor specified pursuant to MRR section 95111 of the ~~variable~~ renewable resource under the following conditions:
>
> (A) First deliverers of replacement electricity have a contract, or ownership relationship, with the supplier of the replacement electricity, in addition to a contract with the ~~variable~~ renewable resource; and
>
> (B) The amount of the reported replacement electricity does not exceed the amount for the reported annual ~~variable~~ renewable resource.
>
> (C) Replacement electricity with an emission factor greater than the default emission factor for unspecified electricity specified pursuant to MRR section 95111 is not eligible to receive an emission factor of zero metric tons CO_2e/MWh. For contracts that use replacement electricity for which the emission factor is greater than the default emission factor for unspecified electricity, the difference between the emission factor from the replacement electricity and the default emission factor for unspecified electricity will be used to calculate emissions with a compliance obligation.
>
> (4) Claims to resources with zero direct emissions, emissions without a compliance obligation, or emissions calculated using a lower emissions factor than the default emissions factor for unspecified electricity specified pursuant to MRR section 95111~~, including renewable resources other than variable renewable resources must demonstrate~~, pursuant to MRR, direct delivery of electricity as defined in section 95802. (SMUD3)

Comment: Section 95802(a)(237) provides that the first point of receipt for renewable energy and any replacement electricity used to firm the delivery must come from within the same balancing authority. LS Power urges CARB to remove this restriction because it will limit the ability of existing renewable transactions to avoid cap-and-trade compliance obligations even though the transaction is consistent with the policies adopted pursuant to the 20 percent RPS laws. Moreover, the definition may be impracticable when it is applied to actual transactions. Many transactions with out-of-state renewables do not identify the source or the balancing authority area for the ancillary and firming services needed to support the renewable generation. Thus, there could be renewable transactions that will face significant GHG compliance costs simply because their contract does not specify the location of the ancillary and firming services. To avoid the unintended implications of this structure, LS Power requests that the Board remove the requirement that replacement power come from the same balancing authority as the source of the renewable transaction. (LSPOWER)

Comment: There is no need for replacement electricity to be sourced from the same balancing authority of the underlying renewable resource. RPS allows firming and shaping resources to be procured and associated with renewable procurement as necessary without consideration of the location of these resources. Entities are free to procure the least cost firming and shaping energy on the market, or to supply firming and shaping from their own resources. Since the default emission rate is the same for any unspecified electricity imported, and is the calculated reduction in GHG emissions allowed for replacement electricity, it does not matter from an emissions perspective which balancing authority the replacement power comes from. A dynamic scheduling agreement approved by CAISO implies that any firming and shaping necessary for an intermittent renewable resource will occur within CAISO, not from the balancing authority in which the resource is located. Tracking replacement energy is a matter of contracts and tags, and is not any more or less complicated when the replacement energy comes from the same balancing authority or another. Modify sections 95802(a)(237) as follows:

(237) "Replacement Electricity" means electricity delivered to a first point of delivery in California to replace electricity from ~~variable~~ renewable resources in order to meet hourly load requirements. ~~The electricity generated by the variable renewable energy facility and purchased by the first deliverer is not required to meet direct delivery requirements. The physical location of the variable renewable energy facility busbar and the first point of receipt on the NERC E-tag for the replacement electricity must be located in the same Balancing Authority Area.~~ (CNE, SMUD3)

Comment: Proposed Regulation should be drafted in a manner that recognizes the fact that if the underlying contractual agreements that utilize replacement electricity (without an intra-balancing authority restriction) are deemed RPS eligible, they should not have a competing compliance obligation under the Cap and Trade Program. Maintaining the strict requirement that the renewable and firmed resources remain within the same balancing authority provides no real benefits to the State, and pits two State policies against each other. Modify section 95902(a)(237) as follows:

(237) “Replacement Electricity” means electricity delivered to a first point of delivery in California to replace electricity from ~~variable~~ renewable resources in order to meet hourly load requirements. The electricity generated by the ~~variable~~ renewable energy facility and purchased by the first deliverer is not required to meet direct delivery requirements. ~~The physical location of the variable renewable energy facility busbar and the first point of receipt on the NERC E-tag for the replacement electricity must be located in the same Balancing Authority Area.~~ (NCPA3)

Comment: The rules for replacement electricity should not apply to renewable contracts executed before the Cap and Trade Regulations are adopted. SCE requests that existing contracts with out-of-state variable renewable generators be “grandfathered,” with all replacement electricity products associated with these facilities automatically counted as zero emissions regardless of how, when, or from where SCE contracts for the replacement electricity. Doing so would recognize the decisions and often long-term commitments made to variable renewable resources across the West prior to ARB’s implementation of the Cap and Trade. It also recognizes that when these contracts were signed, additional costs to customers for GHG treatment of replacement electricity services were not contemplated. Furthermore, renewable generators, who are reducing WECC-wide emissions, would not exist except for the power purchase agreements and long-term financial commitments that SCE and its customers have made. Applying new rules to these contracts would significantly affect the value of existing renewable resources. SCE and other early supporters of renewable resources across the West should not be penalized for proactively undertaking renewable procurement pursuant to the RPS and other state goals. Accordingly, ARB should provide for a limited carve-out to the Cap and Trade rules for the subset of renewable resources that are outside of California and which were executed prior to adoption of these Regulations. That limited set of resources should be allowed to count replacement electricity with a facility-specific emissions factor tied to the renewable resource for the life of the contract, regardless of how, when, or from where such replacement electricity is procured. (SCE3)

Comment: LADWP supports the Joint Utilities position that the definition of replacement electricity should not result in a compliance obligation for renewable resources that meet all the State’s requirements under SBX1 2. This would create an unnecessary cost burden for LADWP’s ratepayers, especially for existing renewable energy contracts that do not include requirements for sourcing replacement power from the same Balancing Authority as the renewable being replaced. LADWP also recommends that the definition of “replacement electricity" be revised to strike the requirement that such resources being replaced be variable. There are instances when transmission outages may warrant replacement of non-variable renewable resources. Modify section 95802(a)(237) as follows:

> (237) "Replacement Electricity” means electricity delivered to a first point of delivery in California to replace electricity from ~~variable~~ renewable resources in order to meet hourly load requirements. The electricity generated by the ~~variable~~

renewable energy facility and purchased by the first deliverer is not required to meet direct delivery requirements. The physical location of the variable renewable energy facility busbar and the first point of receipt on the NERC E-tag for the replacement electricity must be located in the Western Electricity Coordinating Council ~~same Balancing Authority Area~~. (LADWP4)

Comment: The Utilities disagree with the proposal to require that replacement electricity be sourced from the same balancing authority area. There is a disconnect between the firming and shaping requirements for RPS eligible resources as defined in the California Energy Commission's RPS Guidebook and in the MRR. The Utilities and many other California retail providers have contracted for out-of-state wind resources using firming and shaping agreements and would be harmed by the inconsistencies between the State's renewable and GHG policies. Due to the nature of firming and shaping agreements and the inherent lack of transmission, this provision would severely restrict California's electricity providers from the ability to import renewable power from out-of-state. This requirement could exacerbate an already constrained transmission environment between California and the Pacific Northwest. California's utilities will likely incur significant financial impacts from this provision. Utilities will be forced to select among very costly alternatives. CARB staff has indicated that this new definition stems from AB 32 legislation, which requires they must "account for greenhouse gas emissions from all electricity consumed in the State." The Utilities believe that the intent of this section in the statute was not to exclude renewable generation purchased by California's electrical customers. Nor do the Utilities believe it was the intent of the CARB Board to include such a provision that punishes the growth of variable renewable resources when it adopted the Scoping Plan. The Scoping Plan relies on a 33 percent Renewable Electricity Standard (RES) in order to reach the overall GHG reduction goals in AB 32. Absent the recommended revision to the 15-day language, the 21.3 MMT CO_2e of reductions expected from the renewable energy mandates would no longer be valid. Limitations on the use of firmed and shaped products as proposed in both the Cap and Trade and MRR proposed Regulations would be inconsistent with the Scoping Plan and would create a barrier to achieving the relied upon reductions. The Utilities again assert that this provision is a conflict of California State policies. Modify sections 95802(a)(237), 95802(a)(272), and 95852(b)(3) as follows:

(237) "Replacement electricity" means electricity delivered to a first point of delivery in California to replace electricity from ~~variable~~ renewable resources in order to meet hourly load requirements. The electricity generated by the ~~variable~~ renewable energy facility and purchased by the first deliverer is not required to meet direct delivery requirements. ~~The physical location of the variable renewable energy facility busbar and the first point of receipt on the NERC E-tag for the replacement electricity must be located in the same balancing authority area.~~

~~(272) "Variable Renewable Resource" means run-of-river hydroelectric, solar, or wind energy that requires firming and shaping to meet load requirements.~~

(3) Replacement electricity that substitutes for electricity from a ~~variable~~ renewable resource qualifies for the ARB facility specific emission factor specified pursuant to MRR section 95111 of the variable renewable resource under the following conditions:
(A) First deliverers of replacement electricity have a contract, or ownership relationship, with the supplier of the replacement electricity, in addition to a contract with the variable renewable resource; and
(B) The amount of the reported replacement electricity does not exceed the amount for the reported annual variable renewable resource.
~~(C) Replacement electricity with an emission factor greater than the default emission factor for unspecified electricity specified pursuant to MRR section 95111 is not eligible to receive an emission factor of zero metric tons CO2e/MWh. For contracts that use replacement electricity for which the emission factor is greater than the default emission factor for unspecified electricity, the difference between the emission factor from the replacement electricity and the default emission factor for unspecified electricity will be used to calculate emissions with a compliance obligation.~~ (MID3)

Comment: The last sentence of the definition for "Replacement Electricity" should be deleted. There should be no requirement for the replacement electricity to come from the same Balancing Authority Area as the renewable energy. The restriction would unreasonably reduce the flexibility that utilities require to cost effectively obtain renewable energy and will unnecessarily drive up the cost of meeting policy objectives. For example, when the import of renewable electricity from the Bonneville Power Administration Balancing Area in the Pacific Northwest is inhibited by transmission constraints, the acquiring utility should be allowed to use replacement energy from another Balancing Authority. Modify section 95802(a)(237) as follows:

(237) "Replacement Electricity" means electricity delivered to a first point of delivery in California to replace electricity from ~~variable~~ renewable resources in order to meet hourly load requirements. The electricity generated by the ~~variable~~ renewable energy facility and purchased by the first deliverer is not required to meet direct delivery requirements. ~~The physical location of the variable renewable energy facility busbar and the first point of receipt on the NERC E-tag for the replacement electricity must be located in the same Balancing Authority Area.~~ (SCPPA6)

Comment: CARB should remove the restriction in the definition for Replacement Electricity that requires replacement electricity and the renewable energy to be generated in the same balancing authority area. Link the CARB definition of "replacement energy" to the concepts that will emerge from the CPUC and CEC 33 percent RPS proceedings. Modify section 95802(a)(237) as follows:

"Replacement Electricity" means electricity delivered to a first point of delivery in California to replace electricity from variable renewable resources in order to meet hourly load requirements. The electricity generated by the variable renewable energy facility and purchased by the first deliverer is not required to meet direct delivery requirements. ~~The physical location of the variable renewable energy facility busbar and the first point of receipt on the NERC E-tag for the replacement electricity must be located in the same Balancing Authority Area.~~ (IEPA2)

Comment: Replacement electricity should not be restricted to the same balancing authority (section 95802(a)(237)). ARB includes provisions for replacement electricity associated with variable renewables including a requirement that it originate from within the same Balancing Authority. It is assumed that ARB intends to assign default emissions (943 lbs/MWh) to replacement electricity that does not meet this requirement. LADWP has existing contracts for firming and shaping of variable renewables that do not stipulate that the replacement electricity originate from the same Balancing Authority as the renewable resource. As such, these contracts for replacement power may be assigned emissions equivalent to the default emission factor for unspecified natural gas, rather that the emission factor of the renewable resource it is replacing. ARB should provide regulatory relief for such existing contracts and not penalize utilities with legal contracts that do not contemplate these regulatory burdens. Replacement electricity is, for the most part, unspecified and can come from anywhere within the WECC region under the 33 percent RPS. It is problematic for existing firming and shaping contracts that do not include this requirement, as well as for future contracts to the extent that adequate transmission is not available from the same Balancing Authority, such as in the Pacific Northwest region. LADWP is concerned that firming and shaping entities would not support a contract requirement to provide replacement' electricity from within the same Balancing Authority, because compliance may be physically impossible. It could have the unintended consequence of increasing the costs for firming and shaping services. This provision is not a requirement for the 33 percent RPS from an operational perspective. ARB should not distinguish between unspecified power that comes from one Balancing Authority or another, as the same default emission factor is applied to all unspecified power. It appears that there is no added emission benefit or environmental integrity from requiring that it come from the same Balancing Authority. Such requirement should not limit or preclude development of renewable resources. (LADWP4)

Comment: Powerex believes it unreasonable as well as impractical that ARB has limited the benefits of this proposal by requiring importers have “a contract, or ownership relationship, with the supplier of the replacement electricity” and a “contract with the variable renewable resource” in section 95852(b)(3)(A). The supply of replacement electricity is part of a complex supply chain that exists to provide electricity from variable renewable resources. Delivering a steady and reliable stream of renewable energy to a particular customer requires firming (i.e., leveling out variations in the supply of electricity occurring inside an hour) and shaping (i.e., leveling out hour-to-hour variations in the supply) at various stages in the supply chain. All of this firming and shaping comprises the “replacement energy” for the variable renewable resource. The result of this complex supply stream is that the first deliverer of replacement electricity into California may not have direct contractual relationship with the specific variable renewal resource and will often not have a direct contractual relationship with the entities that provided either upstream firming and or upstream shaping services.

As section 95852(b)(3) is currently drafted, without these direct contractual relationships, first deliverers of electricity will not be able to use the variable resource emission factor. To avoid this unnecessary limitation, Powerex encourages ARB to revise section 95852(b)(3)(A) to allow first deliverers of electricity to use the variable resource emission factor if they have "a contract with, contractual claim to, or ownership relationship with the supplier of the replacement electricity, in addition to a contract with or a contractual claim to the output of the variable renewable resource." By including the clause "contractual claim to," the rule will capture the situations where a first importer has purchased electricity that originated from a variable renewable resource and has already been firmed and/or shaped by an entity that is not a party to the transaction that occurs immediately before delivery into California. (POWEREX)

Comment: Section 95852(b)(3)(A) requires that that the first deliverers of the replacement electricity have a contract or ownership with the supplier of the replacement electricity. ARB should clarify the definition of the term "contract" and it should be consistent with industry standard usage of the term. That is, a contract for power specifies a delivery location, delivery time, delivery quantity, price and term. (PGE4)

Comment: BP requests that section 95852(b)(3), defining when Replacement Electricity can be assigned the same emissions factor as the variable energy resource it is firming and shaping, be amended to remove extraneous requirements. First, that section now requires that the "first deliverer" either enter into the firming and shaping contract, or have an ownership arrangement with the source providing the Replacement Electricity. As explained, in many cases the generator will be the party to enter into the firming and shaping contract, although it may not be the first deliverer. However, parties to firming and shaping transactions should be given the flexibility to have a party other than the "first deliverer" enter into the firming and shaping contract. (BP2)

Comment: Modify sections 95802(a)(237) and (272) as follows:
(237) "Replacement Electricity" means electricity delivered to a first point of delivery in California to replace electricity from ~~variable~~ renewable resources in order to meet hourly load requirements. The electricity generated by the ~~variable~~ renewable energy facility and purchased by the first deliverer is not required to meet direct delivery requirements. ~~The physical location of the variable renewable energy facility busbar and the first point of receipt on the NERC E-tag for the replacement electricity must be located in the same Balancing Authority Area.~~

~~(272) "Variable Renewable Resource" means run-of-river hydroelectric, solar, or wind energy that requires firming and shaping to meet load requirements.~~
(JOINTUTILITIES, NCPA3)

Comment: Section 95852(b)(3) contains provisions governing the calculation of the compliance obligation for replacement electricity. For the reasons discussed above regarding the definition of "replacement electricity" in section 95802(a)(145), the restriction to electricity from a “variable” renewable resource should be eliminated because replacement energy may be required to substitute for deliveries from renewable resources such as small hydroelectric projects at impoundments, geothermal projects, biomass projects, and biogas combustion even though those resources are not usually considered to be intermittent. Modify section 95852(b)(3) as follows:

> (3) Replacement electricity that substitutes for electricity from a ~~variable~~ renewable resource qualifies for the ARB facility specific emission factor specified pursuant to MRR section 95111 of the ~~variable~~ renewable resource under the following conditions:
>
> > (A) First deliverers of replacement electricity have a contract, or ownership relationship, with the supplier of the replacement electricity, in addition to ~~a~~ contract <u>or ownership rights to electricity generated by</u> ~~with~~ the ~~variable~~ renewable resource; and
> >
> > (B) The amount of the reported replacement electricity does not exceed the amount for the reported annual ~~variable~~ renewable resource.
> >
> > (C) Replacement electricity with an emission factor greater than the default emission factor for unspecified electricity specified pursuant to MRR section 95111 is not eligible to receive an emission factor of zero metric tons CO_2e/MWh. For contracts that use replacement electricity for which the emission factor is greater than the default emission factor for unspecified electricity, the difference between the emission factor from the replacement electricity and the default emission factor for unspecified electricity will be used to calculate emissions with a compliance obligation. (SCPPA6)

Comment: As currently drafted, section 95852(b)(3)(A) appears to apply only to situations where the first deliverer of replacement electricity (i.e. an Investor Owned Utility) purchases directly from the developer. There is no reason to restrict the market in this manner. Frequently, the commercial reality is that the developer sells the renewable energy and RECs to a firming and shaping party directly who then redelivers energy and RECs to a first deliverer of replacement electricity at the California border. This improves liquidity and is verifiable in the same manner via WREGIS and the NERC e-tag. Modify section 95852(b)(3)(A) as follows:

> (A) First deliverers of replacement electricity have a contract, or ownership relationship, with the supplier of the replacement electricity~~, in addition to a~~ <u>and either the first deliverer of replacement electricity or the supplier of the replacement electricity has a</u> contract with the variable renewable resource; and (MCSG3)

Comment: Pursuant to section 95852(b)(3), Replacement Electricity can claim the same specific emission factor as the variable renewable resource, if the following conditions are met:

1. First deliverers of replacement electricity have a contact, or ownership relationship, with the supplier of the replacement electricity, in addition to a contract with the variable renewable resource; and
2. The amount of reported replacement electricity does not exceed the amount for the reported annual variable renewable resource.
3. Section 95852(b)(3) further specifies that Replacement Electricity with an emission factor greater than the default emission factor for unspecified electricity specified pursuant to Mandatory Reporting Regulation section 95111 is not eligible to receive an emission factor of zero metric tons CO_2e/MWh. For contracts that use Replacement Electricity for which the emission factor is greater than the default emission factor for unspecified electricity, the difference between the emission factor from the Replacement Electricity and the default emission factor for unspecified electricity will be used to calculate emissions with a compliance obligation.

SBx1 2 does specify which party must enter into the firming and shaping arrangement, and does not require the firming and shaping energy to come from the same balancing authority area as the renewable energy being firmed and shaped. Furthermore, the Regulation would in some cases assign an emission factor greater than the variable energy resource to the Replacement Electricity, even though that electricity would count as RPS-eligible under SBx1 2. Doing so would inhibit the development of renewable resources located out-of-state, leading to an increase in the costs of complying with the new 33 percent RPS mandate, and potentially even putting achievement of that goal at risk. (BP2)

> **Response:** The 25 comments above request in various ways that we modify our approach to replacement electricity and to the consideration of RPS-eligible electricity's value in reducing an electricity importer's compliance obligation. Many recommend that we relax the requirement that replacement electricity originate in the balancing authority area (BAA) in which the associated renewable resource is located. Commenters also recommend that we extend the use of replacement electricity to renewable resources that are not variable.
>
> We agree, and we made significant modifications to section 95852(b) regarding the treatment of electricity from renewable resources, and the role of RPS eligible electricity in reducing the compliance obligation of an electricity importer. We deleted section 95802(a)(237), the definition of "replacement electricity." Our new approach relies on an RPS adjustment, which is the subject of new section 95852(b)(4). The RPS adjustment is a quantity of emissions calculated as the product of the default emission actor and the MWh of electricity generated at an "eligible renewable energy resource" (as newly defined), and meeting the requirements of new section 95852(b)(4).

Before making these modifications, we took an approach in which certain delivered quantities of electricity from non-renewable resources (replacement electricity) would be deemed to have an emission factor of an associated variable renewable resource. With the modifications, the regulation now allows for an adjustment in an electricity importer's total compliance obligation based on the amount of RPS-eligible electricity procured or imported that is not directly delivered to California. If RPS-eligible electricity is directly delivered, it receives its actual emission factor, which in many cases is zero.

Our new approach means that we need not consider "firming and shaping" electricity. It also means that the compliance obligation of an electricity importer may be reduced based on the importer's electricity procured from an eligible renewable energy resource, regardless of whether the resource is variable (or intermittent.) Furthermore, because the RPS adjustment is now a term that is subtracted out of the total compliance obligation equation for importers, there is no connection to any electricity that replaces renewable electricity. This means that there is no longer a requirement that replacement electricity originate in a particular BAA.

In considering electricity from renewable resources, we sought a balance between recognizing the value of investments in renewable electricity under the RPS mandate and our need to ensure compatibility with WCI partners when California links with other jurisdictions. We also sought to limit the potential for leakage or "double-counting" of the fact that renewable electricity may be generated with zero, or very low, GHG emissions.

Initially we believed that the correct balance required that replacement electricity be allowed only for variable renewable resources, and that replacement electricity come from generators located in the same BAA as the renewable resource. Through informal discussions and consideration of comments, we came to the conclusion that these restrictions would not necessarily eliminate double-counting and would not necessarily facilitate compatibility with linked jurisdictions more so than our modified approach.

We had initially considered replacement electricity only for variable resources, which, due to intermittency, cannot be directly delivered because they cannot be scheduled across balancing authorities, except in a few limited cases. However, other renewable resources cannot always be scheduled into California due to transmission constraints or other factors. We realized that there would be greater equity for utilities and other electricity importers if the non-variable RPS-eligible electricity could be considered in determining an importer's compliance obligation. To facilitate linkage, and minimize double-counting opportunities, we added new section 95852(b)(4)(E). This new section disallows an RPS adjustment for electricity generated at an eligible renewable energy resource in a linked jurisdiction. We believe that the modifications to sections

95802 and 95852 have met the concerns expressed in the comments above, and have rendered moot their specific proposals for modifications to the regulation.

I-71. Comment: Powerex supports ARB's proposal to allow regulated entities to use the variable resources emission factor for replacement electricity in section 95852(b)(3). Powerex supports the proposed requirement that the volume of replacement electricity not exceed variable generation capacity and that the importer account for emissions differences if the replacement electricity's emissions exceed the default rate. Under the proposed definition of "replacement electricity" (section 95802(a)(237)) in the Cap and Trade Rule, "[t]he electricity generated by the variable renewable energy facility and purchased by the first deliverer is not required to meet direct delivery requirements." Powerex supports this proposal. Due to the unique difficulties in distributing electricity from variable renewable resources, this electricity should be exempt from the Cap and Trade Rule's "direct delivery of electricity" requirements, as that term is defined in section 95802(a)(68). (POWEREX)

Response: We appreciate the commenter's support regarding volumes of replacement electricity. However, within our new approach, we allow both variable and non-variable RPS-eligible electricity to be used in the calculation of the new RPS adjustment. As discussed above, there are difficulties in directly delivering electricity other than that generated at intermittent or variable resources, and we believe that it is equitable to allow both variable and non-variable electricity from RPS-eligible resources to be part of the RPS adjustment.

I-72. (multiple comments)
Comment: The Regulation refers to energy from an intermittent renewable energy facility as "Replacement Electricity," defining it as "electricity delivered to a first point of delivery in California to replace electricity from variable renewable resources in order to meet hourly load requirements" in section 95802(a)(237). The definition further requires that "[t]he physical location of the variable renewable energy facility busbar and the first point of receipt on the NERC E-tag for the replacement electricity must be located in the same balancing authority area." It appears that Replacement Electricity is intended by the CARB to refer to energy that is used to firm and shape a Variable Renewable Resource. However, firmed and shaped energy is not provided in order to "meet hourly load requirements." BP therefore proposes that the first line of the definition be revised to state: "Replacement electricity means electricity delivered to a first point of delivery in California to firm and shape electricity from variable renewable resources." (BP2)

Comment: SCE requests clarification on section 95802(a)(237), requiring that replacement electricity be used to "meet hourly load requirements," as it is currently unclear how this provision is to be monitored or applied. All electricity transactions, including imports, are conducted to meet the customers' hourly load requirements. ARB staff indicated that out-of-state variable renewable electricity generation and its replacement electricity, if any, could be accounted for over the course of one year. SCE strongly supports this annual true-up period, as it fits well with the current operational paradigm used to firm and shape renewable electricity as well as maintains consistency of the treatment of variable renewable resources under the RPS. (SCE3)

> **Response:** Because we deleted old section 95802(a)(237) and modified the regulation's approach to electricity from RPS-eligible generators, these comments are no longer applicable.

I-73. Comment: We recommend that ARB insert "Replacement electricity" as a new category in section 95852.2(a). Replacement electricity is not distinguished from regular market purchases. The compliance obligation should net out the emissions from unspecified imports that are actually replacement power for imported renewables. Modify section 95852.2(a) as follows:

> <u>(a)(13) Replacement electricity pursuant to section 95852(b)(3).</u> (LADWP4)

> **Response:** We did not make this modification. The modifications to section 95852 allow for subtracting the product of the default emission factor and the MWh of certain RPS eligible electricity from an electricity importer's compliance obligation. We believe that these changes have the same effect on the compliance obligation as netting out emissions from unspecified imports that replace renewable electricity. Furthermore, the term "replacement electricity" has been deleted in revisions to the regulation for the reasons previously described.

I-74. Comment: CARB staff has stated that an intra-balancing authority requirement [for replacement electricity and associated variable renewable electricity] is necessary in order to facilitate tracking and verification of these agreements. M-S-R notes that this reliance on the veracity of an E-tag to verify and confirm the source of electricity is misplaced. Rather, these arrangements are already tracked through the Mandatory Reporting Regulation (MRR) in a manner that accurately documents the renewable resource. Accordingly, the simplest solution to resolve the tension that this definition would create between the RPS and GHG reduction goals is, to strike the last sentence of the proposed definition in both the Cap and Trade Regulation and the MRR, and utilize the provisions of the MRR reporting and verification process to confirm these deliveries.

Placing a restriction on "Replacement Electricity" such that it must come from the same BA as where the renewable energy facility is located implies that the source of generation on a NERC E-tag represents a contract between the first deliverer and this source, where in fact, no contract actually exists. This restriction would likely result in market inefficiencies, driving up the cost of electricity and creating potentially higher emissions on a WECC-wide basis. M-S-R understands that CARB must be able to account for electricity delivered into California and verify these transactions without needless administrative burdens. However, this objective is better met by utilizing the current reporting and monitoring practices already utilized by compliance entities with regard to renewable contracts, rather than creating artificial constraints, such as the intra-balancing authority restriction set forth in the proposed definition of replacement electricity. M-S-R (and each of its members) uses the provisions established in the MRR which have proven to be sufficient for purposes of this true-up and verification. The data used to complete this true-up and verification process is already developed by either the facility operator or the shaping and firming entity, and contains the information that CARB needs to verify renewable resource deliveries, where the NERC E-tags do not. Therefore, M-S-R maintains that CARB's objectives are better served by utilizing the existing process in the MRR, rather than looking to NERC E-tags and relying on arbitrary geographical boundary limitations.

If the underlying contractual agreements are deemed RPS eligible, they should not have a competing compliance obligation under the Cap and Trade program. The inclusion of this restriction would preclude entities from being able to maximize their renewable energy contracts, and would result in an added compliance burden associated with renewable energy contracts that were the result of legislative mandates to *increase* renewable energy production. (MSR, NCPA3)

> **Response:** Because these comments concern replacement electricity, they are in large part rendered moot by our modifications to section 95852, discussed in previous responses. However, we do not agree that e-Tags are not useful as part of the process of verifying and confirming sources of electricity. Some e-Tags identify actual generation sources that generate electricity delivered in real time to California, and thus serve to determine source.
>
> In addition, MSR refers to provisions in the MRR for true-up and verification. We do not believe that there are true-up provisions in the MRR. While it is true that our now discarded use of the concept of replacement electricity required comparing renewable generation to replacement electricity, our new methodology for calculating an RPS adjustment requires no true-up. Notwithstanding the fact that NERC e-Tags are not needed for calculation of the RPS adjustment, they are important tools for verification within the MRR, and such verification is needed for accurate calculation of compliance obligations pursuant to this regulation.

I-75. Comment: The requirement in section 95802(a)(237) that replacement electricity originate in the same balancing area, is not aligned with system physical needs or commercial practices. "Firming and shaping" is designed to ensure that an equivalent amount of power delivered into the grid by a renewable resource, and contractually owned by a California LSE, is ultimately physically delivered into the state of California. In some cases, such power will be directly delivered via source to sink scheduling. However, "firming and shaping" services are designed to deliver the same power when such a straightforward "real-time" scheduling approach is not feasible. Potential problems firming and shaping is designed to resolve include transmission congestion between the source and sink Balancing Authority (BA), intermittency of the renewable resource when a firm delivery commitment is needed to ensure load is served, and timing mismatches between generation and load. Firming and shaping deals are designed so that all energy from a contracted, out-of-state renewable resource is disposed of somewhere when it is generated. This must occur even if the energy is not needed in or unable to reach California due to transmission congestion or other reasons. Firming and shaping deals also ensure that an equal amount of energy to the amount generated is physically delivered to a California BA when it can be utilized. Therefore, over time the same amount of energy generated by a contracted renewable resource is ultimately delivered into California. Such a delivery may not be simultaneous, and it may not originate from the same source BA. Renewable energy paid for by California LSEs is injected into the grid outside of California, and is traded for an equal amount of power from unspecified sources delivered into California. Both California law and regulation explicitly contemplate this type of arrangement and deem it (subject to some volumetric limits) to meet requirements for renewable procurement under the RPS statutes. Given these physical realities, and the underlying purpose of "firming and shaping," we believe that replacement electricity, as a practical matter, will hardly ever originate from the same BA as the underlying renewable energy source. Therefore, if the intent of creating a category of energy for reporting purposes called Replacement Energy is to facilitate firming and shaping arrangements in furtherance of State RPS policy, the currently proposed definition, which restricts Replacement Energy to that which originates in the same BA, will not serve that objective. MSCG strongly recommends that the last sentence of the definition be removed. (MSCG3)

> **Response:** As discussed above, we modified our approach and no longer use the concept of replacement electricity. We note that "firming and shaping" appears to have no agreed-upon meaning in the electricity sector, based on various opinions from stakeholders involved in this regulatory process. This regulation relies on tracking direct delivery of imported electricity from source to first point of delivery in California, except that the compliance obligation for an electricity importer may be adjusted for certain RPS-eligible electricity and for certain qualified exports. There is no need to consider the concept of "firming and shaping" for the purposes of this regulation.

I-76. Comment: The definition of "replacement electricity" requires that the physical location of the variable renewable energy facility busbar and the first point of receipt on the NERC E-tag for the replacement energy must be located in the same balancing authority area. SCE recommends that ARB remove this requirement because it is unmanageable from an operational perspective. First, the balancing authorities in which these renewable resources are located may not have the volume of replacement electricity sources necessary to accommodate the need for managing such generation. This may be due to local balancing authority needs if dispatchable resources are needed to support local system load and cannot be exported. Also, many renewable resources are concentrated in a few balancing authorities. This will create an increased demand for "replacement electricity" on top of local balancing needs. Second, the physical transmission path availability from renewable resource balancing authorities into California is limited. Third, most electricity products that are currently traded in the western power markets do not identify the ultimate source of electricity (nor the balancing authority) at the time of the transaction. Requiring the source to be located in the same balancing authority would force market participants to create new, "non-standard" products that specify a balancing authority in its terms. This would bifurcate the common electricity products currently being traded, which may reduce market liquidity and lead to more expensive transactions and rates. Fourth, E-tags are created after the fact. The conventions for specifying the source of electricity on an E-tag are less defined than for other E-tagging conventions. (SCE3)

> **Response:** We deleted the definition of "replacement electricity" to meet this concern. We note that while many or most electricity products currently traded may be forms of electricity from unspecified sources ("for which a source is not identified"), it is necessary to identify generation resources in order to determine the compliance obligation for electricity that is eligible for a specified source emission factor.

I-77. Comment: The definition of "Replacement Electricity" and "Variable Renewable Resource" in the Regulation, and the treatment of energy from Variable Renewable Resources, as defined, is inconsistent with the treatment of these types of transactions in Senate Bill SBx12, and would impose different and additional requirements on firming and shaping transactions than those currently imposed by the California Public Utilities Commission (CPUC) and California Energy Commission (CEC). Below are proposed changes to the proposed regulations that would make the Regulation consistent with SBx1 2 and thus avoid requiring renewable generators to comply with different or additional requirements than those contemplated in SB x1 2. The structure of a firming and shaping transaction depends on a number of factors, including the location of the generator, the purchasing utility, and the firming and shaping party.

However, a basic transaction to firm and shape intermittent energy for delivery to the California Independent System Operator (CAISO) can be described as follows: the eligible renewable generator would enter into a firming and shaping agreement with a third party who would agree to purchase all of the electricity delivered by the intermittent facility as and when generated. The generator would retain the RECs associated with the electricity. The intermittent energy would be measured across an agreed-upon measuring period, which might in some agreements distinguish between energy generated off peak and energy generated on peak. During an agreed-upon re-delivery period, the firming and shaping party would sell and schedule the energy to the seller at a California balancing authority area as a firmed and shaped flat block product that eliminates variability (e.g., as firm energy in 25 MW blocks). The seller would cause the shaped and firmed electricity and the RECs generated by the eligible renewable generator to be delivered to the purchasing utility. For example, assume a wind facility delivers 6,000 MWh intermittently during the course of a measuring period. The shaping and firming party would accept the electricity generated during this period and commit to schedule it into the CAISO during a later re-delivery period, with the 6,000 MWh to be scheduled in flat blocks. In this example, the firming and shaping party could be a party with load (for example, a utility) that would physically absorb the intermittent energy into its system and thereafter re-deliver it during the re-delivery period.

Alternatively, and much more likely in the current market, it could be a company with a trading desk willing to buy seller's intermittent energy as delivered to the facility's interconnection point, sell it into the market and then later acquire electricity and schedule it into the CAISO as a flat and firm product. The measurement period, re-delivery period, shape of re-delivered product, point or points of re-delivery and fee to be paid to the firming and shaping party for the service, among other matters, are not standardized and are subject to negotiations among the utility, the seller and the shaping and firming party. The energy scheduled and delivered to the CAISO in such a transaction is "firm" in the sense that the obligation to deliver it is not unit contingent and can only be excused in very unusual cases of uncontrollable force. It is "shaped" in the sense that it is converted from a variable, intermittent resource with pre-schedule and intra-hour variability into a blocked flat and firm energy product scheduled and delivered to CAISO.

Though firmed and shaped transactions are subject to procurement limits in SBx1 2 there are clear benefits provided by firmed and shaped transactions. Firmed and shaped transactions allow for the more efficient use of the transmission system, as the firmed and shaped product requires less transmission capacity to schedule into a California balancing authority. The resulting reduction in transmission costs can mean lower procurement costs for utilities and their ratepayers. California's electric utility customers would therefore be the ultimate beneficiaries of any resulting reduction in transmission costs. Firmed and shaped transactions also provide additional, incremental energy to California. Nor are the environmental benefits of the renewable generation lost as a result of firming and shaping the output. Even if the product delivered to California is generated by a source other than an eligible renewable energy resource, those deliveries must be equal to generation from the eligible renewable energy resource. At the time the eligible renewable energy resource generates the energy that will later be firmed and shaped, it will replace other sources of generation. In the WECC, the generation is most likely offsetting fossil-fuel fired generation, including coal. In fact, depending on the generation mix where the renewable facility is located, it may reduce greenhouse gas and other hazardous emissions by a greater amount than a facility located in California. Given the nature of greenhouse gas emissions, reductions do not have to occur in California to provide benefits to Californians. (BP2)

> **Response:** The regulation does not consider "firming and shaping," and the single definition that used this phrase (section 95802(a)(272)) has been deleted. Instead, our regulatory approach for the compliance obligation for imported electricity is to track the delivery and ownership or contractual right to electricity from specified sources, and to track electricity from unspecified sources. Due to the modifications in section 95802 and 95852, and the response above to multiple comments on replacement electricity and the treatment of RPS electricity, no additional response is needed.

I-78. Comment: E-tags are designed to track total electrons and therefore do not accurately reflect the contract between the utilities, the renewable generation source, and the source of the replacement electricity. Similarly, a first deliverer who buys power on an electronic exchange such as the Intercontinental Exchange (ICE), at the California Oregon Border, is entering into a purchase of unspecified power from a third party. This third party may have multiple generation resources or none at all and is simply purchasing the energy from someone else. When a first deliverer is contracting for this power they are not contracting for electricity from a specific generation source with a specified emissions output, yet a NERC E-tag must be created to facilitate the BA's management of its net interchange. This NERC E-tag may ultimately be sourced to a coal-fired electric generation facility in Montana, a hydroelectric generation facility in British Columbia, or any number of other resources. Hence, it is highly likely that the actual NERC E-tags generated for the transaction does not accurately represent the source of the generation included in the contract entered into between the first deliverer and the third party.

Placing a restriction on replacement electricity such that it must come from the same BA as the variable renewable energy facility implies that the source generation on a NERC E-tag represents a contract between the first deliverer and this source generation where no such contract exists. This restriction would likely result in market inefficiencies, increasing the cost of electricity and potentially the level of GHG emissions on a WECC-wide basis. Because the E-tags do not necessarily reflect that actual contractual arrangements entailed in the firmed and shaped agreements, the "sources" of electricity included therein would not be accurate, which impacts the emissions factor used to calculate the compliance obligation; an incorrect E-tag can result in considerable added costs. (NCPA3)

> **Response:** In the first paragraph of the above comment, the commenter states that, for certain transactions involving unspecified electricity, it is likely that the e-Tags do not accurately represent the source of generation included in the contract entered into between a first deliverer and a third party. We agree. However, e-Tags are useful to track the delivery of generation between points. The points may include the busbars (first connection) of electricity generating facilities. Some e-Tags demonstrate the origin of electricity at a generation source. A combination of e-Tag information and ownership or contract information is needed for a claim of electricity from a specified source, as set forth in modified section 95852(b)(3) (previously (b)(2)).
>
> We deleted the definition of "replacement electricity," and there are no requirements regarding variable renewable energy and balancing authority origination in the new section 95852(b)(4) that sets forth requirements for the RPS adjustment. These changes render much of this comment moot. However, we do not agree with all of the commenter's characterizations of e-Tags.

I-79. Comment: The current language on replacement electricity raises a number of potential concerns in what is a complicated and evolving area. With that in mind, we strongly recommend the ARB consider a workshop on this issue involving CPUC staff and interested parties to ensure consistency among renewable resources and the Renewable Portfolio Standard (RPS) regulation, and to avoid double counting the environmental attributes of Renewable Energy Credits (REC). (KUSTIN16)

> **Response:** We deleted all language on replacement electricity, and took a new approach to renewable resources eligible for the RPS, as discussed above. We discussed renewable resources in a technical workshop with stakeholders on August 26, 2011, following many hours of discussions between ARB, CPUC, and CEC staff on this issue.

I-80. Comment: CCEEB recommends that ARB provide that resources eligible under the Renewable Electricity Standard (RES) or Renewable Portfolio Standard (RPS) are credited as zero GHG to ensure that the RES, RPS, Cap and Trade, and Mandatory Reporting Regulations are consistent and achieve GHG reductions in the most cost-effective manner. (CCEEB3)

> **Response:** Not all RPS-eligible resources are zero-GHG resources, because some burn fossil fuels. Because this regulation generally imposes a compliance obligation on emissions, and does not generally apply to non-GHG emitting sources as does the RPS, its purpose is very different from that of the RPS, and it would not be reasonable to try to make the RPS and this regulation completely consistent. However, we modified section 95852(b) to allow the subtraction of an RPS adjustment for certain electricity generated from renewable resources but not delivered for consumption in California.

I-81. Comment: Section 95852b(3)(C) states that replacement electricity with an emission factor greater than the default emission factor for unspecified electricity is not eligible to receive an emission factor of zero. Consistent with previous discussions between ARB and stakeholders, we would propose that replacement power procured consistent with the definition for "Unspecified Source of Electricity" be assessed the emissions factor of the underlying renewable resource, which would be zero. Replacement electricity procured consistent with the definition of "Specified Source of Electricity" would be assessed an emission factor, as follows: 1) If replacement electricity is imported in the form of "Specified Source of Electricity," then it would be reported as a specified import, but it would only be assessed an emission obligation amounting to the positive difference between the emission rate of the specified import and the unspecified rate of .428 metric tons per MWh (i.e. (emission obligation of specified import as measured in metric tons per MWh) minus (.428 metric tons per MWh)). To the extent that the specified import has an emissions rate of less than .428 metric tons per MWh, then the specified import would be assessed an emission obligation of the underlying renewable resource, which would be zero. This description would resolve the inconsistency between the MRR and CNT with respect to the treatment of replacement electricity. (PGE4)

> **Response:** Because we no longer use the framework of replacement electricity,

these recommended changes are not needed. We have required the use of the default emission factor for calculating the RPS adjustment of new section 95852(b)(4), which replaces the "replacement electricity" language.

I-82. Comment: Remove restriction to "variable" resources of zero or reduced GHG treatment of replacement electricity. Consistent with the recommendations above regarding treatment of replacement electricity associated with renewable procurement, there should be no restriction in the regulations of associating the emission factor of the underlying renewable resource solely to cases involving variable renewable resources. Modify sections 95852(b)(3) as follows:
(3) Replacement electricity that substitutes for electricity from a ~~variable~~ renewable resource qualifies for the ARB facility specific emission factor specified pursuant to MRR section 95111 of the ~~variable~~ renewable resource under the following conditions:

(A) First deliverers of replacement electricity have a contract, or ownership relationship, with the supplier of the replacement electricity, in addition to a contract with the ~~variable~~ renewable resource; and

(B) The amount of the reported replacement electricity does not exceed the amount for the reported annual ~~variable~~ renewable resource.

(C) Replacement electricity with an emission factor greater than the default emission factor for unspecified electricity specified pursuant to MRR section 95111 is not eligible to receive an emission factor of zero metric tons CO_2e/MWh. For contracts that use replacement electricity for which the emission factor is greater than the default emission factor for unspecified electricity, the difference between the emission factor from the replacement electricity and the default emission factor for unspecified electricity will be used to calculate emissions with a compliance obligation. (SMUD3)

Response: As discussed above, we modified sections 95852(b)(3) and deleted the definition of "replacement electricity" to address these concerns.

I-83. (multiple comments)
Comment: Section 95852(b)(4) addresses claims to resources that have zero direct emissions. The section should be revised as follows, to conform to the elimination (discussed above) of the distinction between "variable" renewable resources and renewable resources that are not generally considered to be "variable." Modify section 95852(b)(4) as follows:

(4) Claims to resources with zero direct emissions, emissions without a compliance obligation, or emissions calculated using a lower emissions factor than the default emissions factor for unspecified electricity specified pursuant to MRR section 95111~~,~~ ~~including renewable resources other than variable renewable resources~~ must demonstrate, pursuant to MRR, direct delivery of electricity as defined in section 95802. (SCPPA6)

Comment: Section 95852(b)(4) states that only variable renewable resources would be exempt from direct delivery requirements. We would propose instead that all renewable resources would be exempt from direct delivery requirements. (PGE4)

> **Response:** We deleted the section, rendering these comments moot. The purpose served by the deleted section is now served by the requirements for claims of electricity with a specified source emission factor (section 95852(b)(3)), as modified. Electricity from sources with zero emissions is essentially a subcategory of electricity from specified sources.

I-84. Comment: Replacement Electricity should always be assigned the emissions factor of the Variable Energy Resource if that Replacement Electricity would qualify as RPS-eligible energy under SBx1 2. We suggest that CARB, rather than attempting to impose its own requirements regarding firming and shaping transactions, which run the risk of being inconsistent with the California Energy Commission's and the California Public Utilities Commission's interpretations of SBx1 2, simply defer to the CPUC and CEC to delineate what types of firming and shaping transactions qualify as the delivery of renewable energy. Otherwise, imposing unnecessary additional requirements or inconsistent requirements will increase the costs of achieving California's renewable energy goals, and will ultimately hurt the California ratepayer. Amending section 95852(b)(3) as suggested would ensure that the three agencies are consistent in their treatment of firmed and shaped energy. Furthermore, we note that although the proposed amendment would eliminate the requirement that the Replacement Electricity not exceed the generation from the variable renewable resource on an annual basis, CEC already applies the same requirement to firmed and shaped transactions that are RPS-eligible. Modify section 95852(b)(3) as follows:

> (3) Replacement electricity that substitutes for electricity from a variable renewable resource qualifies for the ARB facility specific emission factor specified pursuant to MRR section 95111 of the variable renewable resource <u>if that electricity qualifies as firmed and shaped energy pursuant to Public Utilities Code Section 399.16(b)(2) and the California Public Utilities Commission and California Energy Commission regulations implementing that Section</u>. ~~under the following conditions:~~ (BP2)

> **Response:** We have neither imposed, nor tried to impose, requirements for firming and shaping, which we believe are not precisely defined terms in California regulations, and which may or may not be defined in the future for other purposes. We deleted all reference to replacement electricity, rendering this comment moot.

RECs and RPS, including VRE

I-85. (multiple comments)
Comment: REMA proposes that ARB insert some simple additional language to prevent the double counting of emissions associated with electricity imports from out-of-state renewable facilities into California. In addition to the voluntary market for

renewable energy, many western states have mandated renewable portfolio standards (RPS) in order to capture and claim the greenhouse gas and other environmental benefits associated with renewable energy. The renewable energy attributes (including the GHG emission benefits) are contained and conveyed with the REC.

To maintain the integrity of both the voluntary and compliance markets, only the party owning the REC can claim the environmental benefits. When electricity generated by a renewable facility is sold separately from the associated environmental attributes, or RECs, it is no longer allowed to be claimed as renewable or as containing any of the environmental benefits. To do otherwise is double counting. As written, section 95852(b)(2)(B) would allow electricity imports from renewable energy facilities to be treated as emissions free without accounting for the necessary environmental attributes. This constitutes double counting and would severely weaken GHG reduction efforts within the state, region, and voluntary markets.

There are several scenarios in which the electricity imports from specified renewable sources could produce double counting: 1) A renewable energy generator outside of California exports power to California where it is claimed as zero emissions under ARB's Cap and Trade program, while the generator simultaneously sells the associated RECs into the voluntary market or RPS markets outside California; 2) An out-of-state entity purchases bundled electricity (environment attributes and underlying power), and then proceeds to sell the RECs into the voluntary market or RPS markets outside California, while selling the underlying electricity to California as zero emissions for Cap and Trade purposes; 3) A California entity purchases imported bundled electricity (environment attributes and underlying power), and then proceeds to sell the RECs into the voluntary market or RPS markets outside California, while retaining and reporting the underlying electricity as zero emissions for Cap and Trade program compliance. To prevent double counting of emissions claims, REMA recommends that ARB insert the following language as new paragraph section 95852(b)(5). This language prevents double counting and does not conflict with the draft regulation's definitions, does not create new processes, and does not conflict with California statutes. Modify section 95852(b) as follows:

> <u>(5) To report imported electricity from a specified source of renewable energy, the electricity importer must own all property rights to the emissions, or lack of emissions, associated with the imported electricity.</u> (REMA2)

Comment: We believe that section 95852(b) of the draft Regulations could enable the double counting of GHG emissions reductions and therefore undermine GHG emissions reduction goals in the Northwest. We are concerned that it would subvert the legal definitions of RECs adopted by Northwest states, which require all environmental attributes, including GHG emissions reductions, to be transferred with the REC. The aforementioned double counting could be avoided through the adoption of a simple subparagraph following section 95852(b). We recommend that a new section be created as 95852(b)(5) to specify that double counting of GHG emissions reductions is not permitted, while not conflicting with the intent or administration of the regulations or introducing a new compliance mechanism. Due to its heavy reliance on terms already defined in the draft Regulations, the new subparagraph should be a seamless addition. Renumber subsequent subparagraphs accordingly and add new section 95852(b)(5) as follows:

> <u>(5) To report imported electricity from a specified source of renewable energy, the electricity importer must own all property rights to the emissions, or lack of emissions, with the imported electricity.</u> (RNPBEF)

Comment: While sections 95852(b)(3) and 95852(b)(4) require first deliverers to show contract, ownership, or delivery of the underlying electricity from a renewable resource, which then allows them to have no compliance obligation for their import, there is currently no requirement for ownership of the renewable energy certificate (REC) alongside that electricity. As currently written, it is possible for renewable energy facilities outside of California to sell their RECs to meet another state's renewable portfolio standard (RPS), or into the voluntary renewable energy market, and for the underlying electricity to be delivered into California and treated as emissions-free. This results in double counting, as both the entity purchasing the REC and the first deliverer in California are benefiting from the claim of zero-emissions energy from the same MWh of renewable generation.

CPUC defines RECs as embodying all environmental attributes. We strongly recommend that CARB not codify language that directly conflicts with CPUC definitions, and the contractual expectations of REC owners. Enabling the underlying electricity to carry the zero emissions benefit would threaten renewable energy markets wherein RECs are defined as containing all environmental attributes of renewable energy generation. Furthermore, it is possible that entities that have already purchased the zero emissions attributes in the form of RECs will challenge CARB's actions. Further litigation would be likely in order to determine who has title to the zero-emissions attributes. Implementation of this section would make RECs from facilities selling the underlying electricity into California ineligible for Green-e Energy. This would introduce risk into the voluntary market and greatly hinder its growth. This policy would also potentially cause other states to re-evaluate their own successful renewable energy programs and standards. CRS strongly recommends requiring that first deliverers show ownership of the REC in order to claim emissions without a compliance obligation from a renewable resource, or the specific emissions factor of a renewable resource. Sections 95852(b)(3) and 95852(b)(4) should include language stating that "ownership of a REC" be added alongside the other criteria for first deliverers to claim zero emissions. Should CARB be resistant to including this language, a second best solution is to insert the following as a new section 95852(b)(5): "To report imported electricity from a specified source of renewable energy, the electricity importer must own all property rights to the emissions, or lack of emissions, associated with the imported electricity." This will help ensure that multiple claims are not made for the same renewable energy generation, prevent double counting, aid in the continued growth of both voluntary and compliance renewable energy markets in the U.S., as well as guarantee that Californians are actually receiving the zero emissions energy they expect under the Cap and Trade program rules. (CRS2)

Comment: As written, section 95852(b) would allow the double counting of the emissions characteristics if the electricity from an out-of-state renewable energy generator was imported into California and specified as zero-emissions under ARB's Cap and Trade program while, at the same time, the REC associated with the electricity was sold into the voluntary market or a RPS market outside of California. Both the party importing the REC-less electricity, and the party owning the REC would be claiming the same MWh of electricity as zero or reduced emission electricity. This double counting would undermine the environmental integrity of ARB's program and that of the renewable energy market. This potential for two claims on the environmental attributes associated with one megawatt-hour (MWh) is concerning for 3Degrees. We strongly believe that the proposed Regulation should protect against these double claims on emissions characteristics. 3Degrees acknowledges that there are technical difficulties in implementing some proposals to track and assign emissions to null power, but we believe there is simple solution that avoids these difficulties. To protect against double counting, 3Degrees strongly urges ARB to insert the following language as new subparagraph (b)(5) in section 95852. This new language offers protection to non-California RPS and voluntary renewable energy markets, conforms to existing definitions in the proposed Regulation, does not create a new compliance instrument, does not conflict with current California RPS statute, and does not require that ARB create new systems or processes. Modify section 95852(b) as follows:

> (5) To report imported electricity from a specified source of renewable energy, the electricity importer must own all property rights to the emissions, or lack of emissions, associated with the imported electricity. (3DEGREES2)

Comment: SMUD understands that WCI has recommended abandoning the renewable energy tracking system WREGIS for the purposes of tracking purchases of renewable energy under a First Jurisdictional Deliverer framework. SMUD, and other stakeholders in the electricity sector have pushed back against this arbitrary decision given the harm that it does to REC markets, impacting both the cost-effectiveness of the RPS and the credibility of the voluntary renewable energy market. SMUD strongly encourages the ARB to fully vet this topic before making a final decision. The decision reverses legal definitions of Renewable Energy Credits set forth in the Public Utilities Code, and relied on in energy contracts by dozens of entities. It throws into question the underlying value of the RECs tracked by WREGIS, effectively voiding the WREGIS definition, thereby creating further confusion about legal claims that can be made regarding contracts involving this commodity.

The reasoning offered by the WCI decision, primarily the administrative burden of tracking REC ownership and claims made by purchasers of null power, ignores the new administrative burden that is created for the reporters of these transactions, who now have the very tool that was created to track renewable energy claims taken away, leaving them in a predicament of relying on vague language in a reporting regulation to base long term contracts on. The decision calls into question the claims that are made in the voluntary renewable energy markets around the benefits that are embedded in RECs, thereby undermining the value of this market perhaps in a bigger way than the decision of whether or not to create a set-aside.

In addition to fully capturing stakeholder input on this important topic, ARB should consider the cost implications of adopting this policy on RECs. The use of RECs for RPS compliance was intended to help reduce the need for building high cost and difficult to permit transmission for renewable energy, as well as to make tracking of renewable claims easier. By requiring entities to purchase both the energy and the REC in order to receive the specific emission signature of the renewable resource, the ARB is effectively eliminating, or greatly limiting the viability of, using unbundled REC's for RPS compliance. This policy is not only inconsistent with the RPS but will either increase costs under the RPS or increase costs under the cap and trade program as entities opt to purchase RECs and are required to come up with additional allowances. Considering the RPS is one of the most expensive policies under the full set of AB 32 policies, and was expected to result in substantial reductions in the scoping plan, the ARB should give strong consideration to policy decisions which either inflate its cost or reduce its effectiveness in contributing to statewide emissions reductions.

Specific changes to the cap and trade regulation would be to recognize that all State recognized renewable energy resources procured for the RPS should be exempt from a compliance burden associated with their purchase. Modify section 95852.2 and 95852(b)(2)(D)as follows:

> <u>(g) Reserved for future consideration of treatment of combustion emissions associated with power delivered along with RECs.</u>
>
> (D) If there are other parties within the contract chain of custody, then the original source of generation and quantity of MWhs to be delivered under the original contract must be identified within the entire contract chain. <u>RECs in the form of WREGIS certificates are sufficient to meet this documentation requirement.</u> The quantity of electricity delivered, and for which an ARB facility specific emission factor specified pursuant to MRR section 95111 is claimed, cannot exceed the original amount under ownership or contract rights reported pursuant to section 95852(b)(2)(A). (SMUD3)
>
> **Response:** While we reject the commenters' assertions about what a REC includes for reasons put forth below, we understand that many individuals and entities believe that RECs represent a reduction in GHG emissions. We agree that double-counting is very likely to occur if RECs are sold separately from electricity delivered from a renewable resource and the REC is not accounted for. We agree with the commenters that in order to claim electricity from a specified source when it is an eligible renewable resource and RECs have been created to represent that the electricity came from a renewable resource, it is critical that such RECs should not also be used in other programs to claim

a reduction in GHG emissions. Therefore, we modified section 95852(b)(2) by adding paragraph 95852(b)(2)(D) to require that RECs, if created, must be retired for electricity for which a specified source claim is made.

To further clarify the issue of RECs, we first explain why we do not agree that RECs can be used to reliably prevent double-counting. Then we document the fact that, in California, RECs do not have a “GHG emissions attribute” once a cap is in place. We also explain why electricity from which a REC is separated cannot be said to have GHG emissions without a regional “null power” tracking system. Finally, we respond to additional specific points of the comments above.

REMA asserts: “When electricity generated by a renewable facility is sold separately from the associated environmental attributes, or RECs, it is no longer allowed to be claimed as renewable or as containing any of the environmental benefits. To do otherwise is double counting.”

We agree. However, the electricity does not acquire GHG emissions because RECs were separated. RECs and the WREGIS tracking system for RECs can ensure that RECs are not used in more than one jurisdiction’s RPS, provided all programs and generators participate in WREGIS. Regardless of any claims made or not made by any entity, double-counting of a GHG emissions attribute can easily occur even if RECs are retired because electricity from a GHG-free generation source is, in actual fact, generated without any GHG emissions.

For example, assume that a Walmart store in Oregon purchases electricity from a wind generator in Oregon for which the wind generator makes no claims of any kind. Walmart officials can claim, truthfully, that they are purchasing electricity that had no GHGs emitted in its generation. However, if a California utility purchased an REC from the wind generator, and if REC had an attribute of reducing GHG emissions, then a California utility could purchase and retire the RECs and claim to have reduced GHG emissions. Even if the WREGIS system requires the generator to agree to make no claims about the environmental attributes of the electricity, Walmart would be correct in claiming that there were no GHG emissions created during generation at the wind source. The reason this is so is that, the non-emission of GHGs is not an attribute, but the lack of an attribute. If a California utility were to use an REC from the wind generator in a capped jurisdiction to make a claim about reduced GHG emissions, that would be double-counting. This is true because if the wind generator is in a capped jurisdiction, it has no compliance obligation and does not reduce emissions in that jurisdiction.

The only way to ensure that there is no double-counting when RECs are separated from electricity is to have a multi-jurisdictional regulatory program that would assign GHG emissions to “null power,” which is the common name for electricity from a renewable resource from which RECs have been separated. Because there is no regime that assigns emissions to renewable electricity (null power) and tracks the electricity to the point of consumption, and requires the end-user to make not claims, it is impossible to prevent some double-counting when RECs are used.

We are evaluating whether to use WREGIS as a system to track renewable electricity. Most importantly, ARB needs to be assured that WREGIS or any system used to track renewable electricity is as thorough and rigorous as the reporting and verification requirements included in the MRR and used for determining compliance obligations under this regulation.

Many commenters share a common misunderstanding of the value of RECs as set forth in law or in regulatory proceedings. Much of the consideration of RECs in California has taken place in CPUC proceedings.

Some commenters assert that RECs contain environmental attributes, including "GHG emission benefits." Other commenters agree with the CPUC that RECs contain an "avoided emissions" attribute. Some claim that legal definitions of RECs adopted by Northwest states require all environmental attributes, including GHG emissions reductions, to be transferred with the REC. 3DEGREES provided many definitions from other states and programs, and many include "avoided emissions." However, renewable electricity may or may not result in avoided emissions. Regardless of definitions in other states, California and WREGIS definitions of RECs do not include "GHG emission benefits." And in California, because there is now a cap on GHG emissions, although renewable electricity may help to meet the cap, it cannot be said to truly avoid emissions because emitters as a group will emit up to the cap.

On page 105, Appendix M to the staff report (the joint CPUC-CEC recommendation to ARB) states:

"In anticipation that tradable RECs may be authorized in the future, the Public Utilities Commission stated recently in D.08-08-028 that,

> '[O]nce a REC is used for RPS compliance (either before or after a GHG cap is imposed), the REC cannot also be used as a GHG emissions offset. In addition, once a GHG cap is imposed, RPS-eligible generation subject to a cap never avoids emissions. The "avoided emissions" will continue to be included in the REC, but the avoided emissions will be zero; the balancing GHG emissions value of the null power will therefore also be zero. Thus—assuming that ARB adopts this analysis—our characterization of the REC will not require any RPS-eligible generation with zero GHG emissions to need allowances when delivered to the California grid [footnote omitted]. (D.08-08-028, mimeo. at p. 24.)"

We agree with the CPUC that, once a GHG cap is imposed, RPS-eligible generation subject to a cap never avoids emissions (unless allowances are retired such as the case with the voluntary renewable electricity set-aside). We also agree that RPS-eligible generation with zero emissions will not need allowances if it is actually delivered in real time to the grid.

Furthermore, the CPUC is on record in the footnote omitted above that even though avoided emissions are part of a WREGIS Certificate, that does not mean that avoided emissions, if they have a positive or zero value, can be used in a GHG regulatory program. CPUC was anticipating the fact that whatever value—negative, positive, or zero, for an avoided emissions attribute— it was up to WCI (regionally) and ARB (in California) to determine how such value might be treated.

We note that generation of renewable electricity may or may not result in avoided emissions greater than zero, as explained by CPUC above.

Finally, California recognizes the use of WREGIS certificates. WREGIS's web page shows a definition for their certificates, and the commenters are in error about what the definition is.

I-86. Comment: Although PG&E appreciates ARB's intent to address utility concerns regarding the treatment of renewable electricity, the new provisions, as currently drafted, would prevent PG&E from being able to count existing out-of-state RPS-eligible contracts as zero GHG and would limit our ability to count future out-of-state contracts which we are allowed to pursue under the existing 33 percent legislation as zero GHG. California utility customers should receive credit for the zero-GHG attributes purchased through renewable contracts and should not be required to pay twice for GHG reduction benefits. (PGE4)

Response: It is clear from the previous response that there are no transferable "zero-GHG attributes" associated with renewable electricity. We note that the CPUC, which regulates PG&E, has made it clear that once a GHG cap is imposed, RPS eligible generation subject to a cap never avoids emissions.[8]

There is nothing in the regulation "that would prevent PG&E from being able to count existing out-of-state RPS-eligible contracts as zero GHG" although generally contracts are not considered to have, or not have, emissions of any kind. However, as discussed in our response regarding replacement electricity, we modified section 95852(b) and allow for an RPS adjustment that

[8]Op. cit., Appendix M to the Staff Report, page 105.

essentially gives first deliverers credit against their compliance obligation for RPS electricity procured.

Voluntary Renewable Energy

I-87. Comment: SCE supports ARB's decision to use allowances retired in the amounts matching emissions reductions due to voluntary renewable energy procurement for retirement and not direct them to alternative uses. (SCE3)

Response: We thank SCE for their support.

I-88. Comment: Any allowances in the Voluntary Renewable Electricity Reserve Account that are not retired on behalf of voluntary renewable energy procurement should be returned to the market via the quarterly state auction in a timely manner. SCE recommends that any year that the number of current year vintage allowances in the Voluntary Renewable Electricity Reserve Account exceeds the number of allowances retired under this program, these excess allowances should be returned to market through the next quarterly auction. (SCE3)

Response: We do not agree that unused allowances should be returned to the market via quarterly auction. Allowances will be deposited into the Voluntary Renewable Electricity Reserve account and will remain in the account until participants request allowance retirement for contributions of eligible renewable electricity according to section 95841.1. Considering the current rate of growth of the voluntary market, it is our expectation that participants will request that all allowances be retired.

I-89. Comment: Section 95870(c) designates percentages that, when applied to allowance budgets for years 2013-2020, would determine the quantity of allowances transferred to the Voluntary Renewable Electricity Reserve. PG&E believes that because allowances transferred to the Voluntary Renewable Electricity Reserve would no longer be available to greater market participants, the reduction in allowance supply to the market by adding a Voluntary Renewable Electricity Reserve has the potential to increase allowance prices and compliance costs. Therefore, PG&E only supports set asides that achieve actual reductions. (PGE4)

Response: Once the cap is in place, the only mechanism for creating reductions in emissions from voluntary renewable electricity (VRE) is the retirement of allowances, thus reducing the cap. We agree that allowance retirement should be only for actual reductions in emissions from contributions to the electricity grid from VRE purchases. Allowances will be deposited according to section 95870(c) and will remain in the account until a retirement request, with the accompanying required information, is received. Allowances will only be retired when VRE participants demonstrate, pursuant to modified section 95841.1, that renewable electricity meeting the section's requirements was generated during the year for which allowances will be retired. This is a transitional program. Currently, with no cap, voluntary renewable energy projects reduce GHG emissions and help meet the electricity demand, obviating the need for system electricity.

I-90. Comment: The proposed VRE set-aside modifications in section 95870 place a cap on the total allowances allocated to the VRE set-aside for each compliance period. REMA urges ARB not to adopt a pre-determined cap and to allow budget adjustment to be determined by demonstrated demand. An inflexible cap would place an artificial ceiling on the growth of the voluntary market for renewable energy, while an annual adjustment would provide flexibility and encourage additional demand for VRE purchases. ARB has recognized that voluntary demand for renewable energy helps reduce greenhouse gas emissions, and an annual adjustment would ensure that renewable energy supported by the voluntary market in fact reduce emissions by retiring allowances.

However, should ARB decide to maintain its proposed VRE allowance cap, REMA strongly recommends that section 95870(c) ("Disposition of Allowances") be revised to allow allowances to roll-over into future years whenever VRE set-aside allowance supply exceeds demand. This, at the very least, will create a slim buffer to allow for VRE market growth in the succeeding years. Also, REMA recommends the cap be subject to periodic review and adjustment prior to the start of each compliance period, or that an automatic review be triggered whenever demand exceeds the cap for two consecutive years. Several RGGI states have adopted a similar provision. (REMA2)

Response: We acknowledge REMA's concern; however, there is no need to roll allowances over because the allowances will remain in the account until we receive a request to retire them in accordance to the requirements contained in section 95841.1. We estimated the contributions from the voluntary sector as well as the market growth from 2007 through 2009. Our analysis indicates that allowances allocated for VRE should meet market demand, at current growth rates, at least for the initial years of the regulation. We view the account as a type of transitional assistance to help the voluntary market transition to a GHG constrained market. As discussed above, we expect, with decreased costs for renewable electricity over time and increasing carbon costs for electricity generated from GHG emitting resources, the VRE market will not need set-asides. Owners of buildings and businesses, and those wishing to voluntarily reduce GHG emissions and support the voluntary market, will continue to make these purchases, which will transition to reflect the carbon cost. The voluntary market will eventually need to purchase allowances and retire allowances to continue to make the GHG reduction claim. The allowance cost should be included with the sale of the VRE, if purchasers wish to claim their renewable electricity reduces GHG emissions.

I-91. Comment: The Utilities continue to have concerns with the inclusion of a VRE component at the outset of the Cap and Trade program as such component will, by design, remove compliance instruments from the market leaving fewer allowances available for covered entities, which in effect reduces the cap below the goal set by AB 32. The Utilities are also concerned that the VRE market will act in direct competition with the 33 percent RPS market, constraining all electric distribution utilities in their effort to meet their compliance obligations under both the RPS and the cap and trade programs. This would increase the overall costs of compliance and the compliance burden for covered entities. The Utilities recommend the following changes in an effort to minimize the impact from such a program. Modify section 95870 (c) as follows:

> (c) Recognition of Voluntary Renewable Electricity Emissions Reductions. On December 15, 2012, the Executive Officer shall transfer allowances to the Voluntary Renewable Electricity Reserve Account, as follows:
>
> (1) 0.~~5~~10 percent of the allowances from budget years 2013-20~~14~~20; ~~and~~
>
> ~~(2) 0.25 percent of the allowances from budget years 2015-2020.~~ (MID3)

> **Response:** We do not agree with the modifications proposed by MID. The purpose of the voluntary renewable electricity component is to ensure emission reductions for voluntary renewable electricity generation that reduces the need for system electricity after the cap is in place. This is a transitional program. Ultimately we expect renewable electricity and other low GHG-emitting generation to become the best economic choice for many businesses and homeowners as carbon costs rise. This renewable electricity reduces the electric load that must be served by electric utilities, which means the utilities will have less need for allowances. If allowances were not taken out of circulation for renewable energy that is voluntary, there would be a surplus of allowances in circulation for emissions that did not occur. If allowances were not retired, quite the opposite would happen to allowance prices than what MID describes. Surplus allowances would put downward pressure on allowance prices, reducing the incentive to reduce emissions.

I-92. Comment: CARB should outline what will happen if the number of allowances requested for retirement exceeds the size of the set aside specified in section 95870(c). The preferable solution would be to follow the RGGI Model Rule, and "true up" allowances at the end of each compliance period. In this scenario, a predetermined amount of allowances are taken out of circulation at the beginning of the compliance period. At the end of the period, if the number of allowances requested for the voluntary market exceeds the set aside amount, then the appropriate number of allowances are taken out of circulation in the subsequent compliance period. Having a truing up mechanism reduces the risk that there will not be enough allowances for all voluntary sales in a given year. This provides more market certainty and aids in the growth of renewable energy capacity in California. If it is not possible to exceed the amount prescribed in section 95870(c), the second best solution is to roll over any excess allowances from the set aside at the end of each year such that they can be used in the event the set aside is oversubscribed in future years. Regardless of the approach taken, CARB should specify what happens if the set aside is oversubscribed, and what happens with potential excess allowances, so that there is certainty to all market participants. (CRS2)

> **Response:** We acknowledge that most RGGI states allow a true-up of allowances for voluntary renewable electricity at the end of each compliance period. However, our emissions trading scheme is more comprehensive than RGGI's, and our initial rollout will provide transitional assistance to the industrial sectors to address leakage. Our program will also initially allocate allowances to the utilities for AB 32-related purposes. As such, we have a limited supply of allowances for each of the compliance periods. We estimated the demand growth of the VRE market, and we expect the number of allowances to be equivalent to this expected demand under current growth rates. Once the account has been depleted then the program will cease; however, as discussed above, we believe the voluntary market for renewable electricity will continue to thrive, as renewable self-generation becomes an increasingly attractive economic choice, which will reduce the cost of renewable electricity.

I-93. Comment: Section 95831(b)(6) creates a Voluntary Renewable Electricity Reserve Account to set aside allowances that may be retired to account for voluntary renewable electricity. Section 95841.1 explains the program requirements and calculations for voluntary renewable electricity. SCE maintains that in order to qualify for the retirement of allowances from the Voluntary Renewable Electricity Reserve Account, the voluntary renewable energy procurement must satisfy the same rules as utilities in order to show mandatory renewable energy purchases as zero emission. ARB has indicated that any renewable generation must be California RPS-eligible. SCE encourages ARB to clarify that any voluntary renewable energy purchase must satisfy the same rules as the compliance market to be recognized as zero emissions under the Cap and Trade program. (SCE3)

> **Response:** We modified section 95841.1 to clarify and add new requirements for electricity eligible for the VRE program. The VRE program requires all electricity to be directly delivered to the California grid, and to meet the requirements of either the RPS or the CEC's *Guidelines for California's Solar Electric Incentive Programs.* As such, the requirements for the VRE sector are more stringent than those for the RPS delivery requirements.

I-94. Comment: SMUD has long supported the concept of a set-aside of allowances for the voluntary renewable market, where those allowances are retired as voluntary renewable procurement occurs. However, the restriction in the provisions to only renewable energy that is "directly delivered" to California is inconsistent with the practice in voluntary renewable markets and is unnecessary in the cap and trade program. Allowances should be retired, ensuring GHG reductions in California, regardless of whether or not renewable electricity was directly delivered to California or is associated with replacement power delivered to California consistent with the allowed flexibility in the RPS and the voluntary renewable market. Modify section 95841.1(a) as follows:

(a) Program Requirements: The end-user, or VRE participant acting on behalf of the end-user, must meet the requirements of this section. Generation must be new and not have served load prior to July 1, 2005. Allowance retirement for purposes of voluntary renewable electricity will begin in 2013 for 2012 generation. ~~Eligible renewable electricity, or renewable electricity associated with RECs, must provide direct delivery of electricity to California.~~ (SMUD3)

Response: We do not agree. If electricity is not directly delivered, then other electricity, often from fossil generation, would be delivered. Retirement of allowances within the California program needs to occur for direct reduction in emissions for electricity that is sent to the California grid.

I-95. Comment: While SMUD commends the inclusion of a provision in Section 95841(b)(3) for aggregation of smaller resources (less than or equal to 200 kW), SMUD notes that such resources may not have an RPS generator identification number, particularly since voluntary renewable resources are not part of the RPS. SMUD contends that there is no reason for requiring a specific identification number for these resources. (SMUD3)

Response: We agree, and we included an option for participants in 95841.1(b). If the generator is not registered as RPS eligible by the CEC, then the participant may refer to the design and installation requirements contained in the California Energy Commission's *Guidelines for California's Solar Electric Incentive Programs,* third edition, June 2010. Participants will need to submit evidence that they met the installation and verification requirements in these guidelines by providing documentation that they received their incentive.

I-96. Comment: Section 95841.1(b)(1)(A) refers to the requirements of "…section 95841.1(b) (3) or (4), as applicable;" but there is no section 95841(b)(4). SMUD believes that the proper reference should be for subparts (2) or (3) as applicable. Modify section 95841.1(b)(1)(A) as follows:

(A) Report to ARB the quantity of renewable electricity in MWhs, and/or the number of RECs generated during the previous year from an eligible renewable electricity generator that meets the requirements of section 95841.1(b)(2~~3~~) or (3~~4~~), as applicable; (SMUD3)

Response: We acknowledge the typographical error and in section 95841.1(b)(1)(A) we corrected the references to sections 95841.1(b)(2) and (3), as applicable.

I-97. (multiple comments)
Comment: Sections 95481.1(b)(2)(D) and 95481.1(b)(3)(E) require "REC retirement reports" to be submitted by voluntary renewable energy participants seeking allowance

retirement. The term REC retirement report is not defined within the regulations and CRS seeks more detail on what such a report encompasses. (CRS2)

Comment: Section 95841(b)(2)(D) and Section 95841(b)(3)(E) refer to a "REC retirement report", but this report is never defined. If this simply refers to the report required by Section 95841 in general, there is no need for these subsections. Modify sections 95841(b)(2) and 95841(b)(3) as follows:

> (2) VRE Participants seeking allowance retirement for renewable electricity generation from an eligible facility > 200 KW nameplate capacity must submit the following with the report required in this section:
>
> > (A) Provide the RPS generator identification number, as determined by the California Energy Commission;
> > (B) MWhs of renewable electricity generated; and
> > (C) Number of RECs, as applicable; ~~and~~
> > ~~(D) REC retirement report.~~
>
> (3) VRE participants seeking allowance retirement for renewable electricity generating from an eligible facility ≤ 200 KW nameplate capacity must submit the following with the report required in this section:
>
> > (A) Application must be for retirement of more than an equivalent of 150 metric tons CO_2e. Applicants may aggregate eligible systems to meet this threshold requirement, but must submit only one application under one entity;
> > (B) Provide the RPS generator identification number, as determined by the California Energy Commission;
> > (C) MWhs of renewable electricity generated; and
> > (D) Number of RECs, as applicable; ~~and~~
> > ~~(E) REC retirement report.~~ (SMUD3)

Response: It is our intent to use terms accepted by the industry. We understand that most of the VRE industry, as well as western states with RPS mandates, use WREGIS to track RECs, and we expect that the WREGIS REC retirement report will be used by most VRE participants. However, for very small generators the cost of registering with WREGIS, or other costs associated with creating RECs, could be prohibitive. We included an option for participants to submit "tracking system data," which is another industry accepted name for data documenting REC retirement and/or renewable electricity generation. We made modifications to section 95841.1(b)(1), (b)(2) and (b)(3) to allow tracking system data as an alternative to a REC retirement report or proof of purchase or sale.

I-98. Comment: SMUD appreciates and supports the addition of specific voluntary renewable provisions in the 15-day language. The purpose of the voluntary set-aside is to assure that renewable generation used to meet voluntary market demand actually results in reductions of greenhouse gases beyond those already required by the cap once a cap and trade program is put in place. The application of this set-aside to renewable projects has been restricted to those projects that are located in the State, or that dynamically transfer their energy into the State, and that have been installed after January 1, 2005. Given that ARB set the cap based on emissions expected to occur in the State in 2012, the application of the set-aside to projects installed between 2005 and 2012 is not necessary. Such application would potentially create a doubling of the apparent reductions of those projects. Because the projects that were installed in this time-period are already displacing emissions, ARB has already effectively set aside and retired the allowances that would have otherwise been associated with these through its cap-setting process. Had the renewables not been installed, the cap would be higher.

So, the renewable projects are already displacing greenhouse gases, and even if they were to go away at some future date, their impact is locked in by virtue of their having impacted the cap at the time it was set. The only renewables that require a voluntary set-aside would be those renewables that were brought online after the cap was set that were then sold to the voluntary market. These renewables would not affect the cap trajectory without a set-aside. Adopting such a policy would also allow for more new renewables to be brought online for the voluntary market, rather than creating a situation where existing renewables were claiming much of the set-aside when it was not necessary. Such a decision would only negatively impact existing renewable projects if Green-e chose to require that they hold set-asides, however such a decision is unnecessary, the existing renewable are already displacing fossil generation and the cap setting process assures that they will in perpetuity. Modify section 95841.1(a) as follows:

> (a) Program Requirements: The end-user, or VRE participant acting on behalf of the end-user, must meet the requirements of this section. Generation must be new and not have served load prior to ~~July 1, 2005~~January 1, 2012. Allowance retirement for purposes of voluntary renewable electricity will begin in 2013 for 2012 generation. Eligible renewable electricity, or renewable electricity associated with RECs, must provide direct delivery of electricity to California. (SMUD3)
>
> **Response:** We do not agree with the proposed on-line date. The July 2005 date coincides with the release of Governor Schwarzenegger's Executive Order S-3-05, which established the climate change emission-reduction targets for California. In addition, we want to ensure that the generation that is supplying the voluntary sector and results in allowance retirement is efficient and representative of technology approved by the CEC. This date ensures this intent. In addition, to be eligible for the RPS, out-of-state facilities must have come on-line in 2005 or later.

I-99. Comment: Section 95841.1 requires that a renewable energy credit must be retired prior to the retirement of an allowance from the Voluntary Renewable Electricity Reserve account. Based on discussion at ARB's July 15 public workshop, PG&E understands that the percentages in section 95870(c) are based on projections, derived from historic data, on demand for Voluntary Renewable Electricity Credits. Therefore, it is possible that the quantity of allowances in the Voluntary Renewable Electricity Reserve Account could exceed the quantity of RECs retired per section 95841.1, leaving a balance in the account. In the event that allowances in the Voluntary Renewable Electricity Reserve are not retired at the end of each compliance period, PG&E requests that ARB return those unused allowances to the total pool of allowances available to market participants. (PGE4)

> **Response:** This issue was addressed in the response above to SCE3. The unused allowances will not be placed into any other account. They will remain in the VRE reserve account. At the commencement of the second compliance period any unused allowances will remain in the account, and additional allowances will be placed into the account each year. Once the account has been depleted it will be closed.

I-100. Comment: The Board should keep in mind that it is through the addition of more renewables that the State will actually reduce carbon emissions in the electricity sector. Limiting the term of the VRE set-aside through section 95870 sends a poor market signal for the investment in renewable generation. Should ARB maintain its set-aside time limit (proposed currently as 2020), it should undertake a general stakeholder review process in the future to examine the market evidence and determine whether a sunset on the set-aside is indeed merited or if an adjustment is more appropriate. Finally, if ARB decides to end the VRE set-aside, it should be careful to base the sunset on the date of project installation, not on the date of the RECs or output. Renewable developers who make investment decisions based on a set of assumptions about market support should not have the rug pulled out from under them. That kind of risk will deter new investment. (REMA2)

> **Response:** We acknowledge the concern regarding sending a market signal for the continued investment in renewable generation. However, the program allows for a limited number of allowances available for voluntary renewable generation during a transition period. In the long-term, we expect that the carbon price signal in electricity from GHG-emitting generation will encourage investment in low- and zero-GHG emission electricity, including renewable electricity. We also note that VRE market participants can choose to register as a voluntarily associated entity, purchase allowances, and retire them, to ensure continued emission reductions for renewable electricity in a capped jurisdiction.

I-101. (multiple comments)
Comment: REMA recommends that any shortage of allowances in the VRE set-aside for a given year be remedied by increasing the next year's ex-ante adjustment by the amount of the shortage, and immediately (in the new year) retiring allowances commensurate with the shortage. Consumer-led growth of the renewable energy sector should be reflected in a true-up that recognizes the voluntary market's progression. If this cannot be done, then REMA recommends that ARB embrace a policy prohibiting the release of any excess allowances in the set-aside account, and instead carrying

them forward to be used in any year when voluntary demand exceeds the ex-ante adjustment for that year. This issue is critical because it will be impossible to ensure that a purchase is meaningful if it is uncertain that it will result in the retirement of equivalent allowances. Purchasers must know that they are going to get what they intended to buy. In the event that demand for the voluntary set-aside exceeds the year's allowances and neither the program cap nor the two-way true up is revised, REMA recommends that allowances are distributed and retired equally amongst program participants. (REMA2)

Comment: As stated in previous comments, 3Degrees urges ARB not to adopt a pre-determined cap and to allow the budget adjustment to be determined solely by the ex-ante estimate of need based on demonstrated demand (section 95831(b)(6) Voluntary Renewable Electricity Reserve Account). This will send a clear market signal and promote the continuing future growth of voluntary renewable energy purchases. Should ARB decide to pursue a cap on the number of allowances that can be placed in the holding account, 3Degrees strongly recommends that the cap be subject to annual review and adjustment rather than at the start of each compliance period, or that an automatic review be triggered whenever demand exceeds the cap for two years in succession. (3DEGREES2)

Comment: 3Degrees urges ARB not to adopt a pre-determined cap and to allow the budget adjustment to be determined solely by the ex-ante estimate of need based on demonstrated demand. Should ARB decide to cap the number of allowances that can be retired each year, 3Degrees strongly recommends that the language in section 95841.1(c) be amended such that in the case that demand for VRE allowances exceeds supply in a given year, ARB should distribute and retire VRE allowances distribution equally among qualifying MWhs and/or RECs. As written, the proposed regulation is unclear on this point. In the case of demand for VRE allowances for not equaling supply, then ARB should roll over excess allowances into future compliance years. This, at the very least, will create a slim buffer to allow for VRE market growth in the succeeding years. (3DEGREES2)

> **Response:** The regulation contains no provision for an "ex-ante adjustment" or for increasing the allowances allocated to the VRE Reserve Account above the percentages set forth in Section 95870(c). This is because we expect the market to grow sufficiently and meet the quantity allocated to the VRE Reserve Account. As discussed above, this is a transitional program. In the long term, we expect the carbon price signal to provide support for electricity generation that has zero- or low-GHG emissions.

I-102. Comment: REMA recommends several clarifications to the set-aside's REC retirement, allocation, and program provisions that would improve upon the proposed draft language and match the environmental commodity industry's best practices. First, REMA's suggestions would modify ARB's descriptions of RECs to align more clearly with industry standards. Second, the recommendations would clarify the role of voluntarily retired RECs in the set-aside program. Finally, REMA recommends that VRE set-aside participant regulatory responsibilities be limited to the set-aside program only. Extending overall Cap and Trade responsibilities to parties only participating in the set-aside could impose overly burdensome compliance obligations, limiting private participation. Modify sections 95841.1(a), (b)(2)(B), (b)(2)(C), (b)(1)(E)(2), and (c) as follows:

(a) Program Requirements: The end-user, or VRE participant acting on behalf of the end-user, must meet the requirements of this section. Generation must be new and not have served load prior to July 1, 2005. Allowance retirement for purposes of voluntary renewable electricity will begin in 2014 for 2013 generation. RECs associated with renewable electricity, or eligible renewable electricity, must provide direct delivery of electricity to California.

(B) MWhs of renewable electricity generated designated for VRE retirement;
(C) Number of RECs designated for VRE retirement, as applicable;
(2) Attest, in writing, to ARB as follows: “I understand I am voluntarily participating in the California Greenhouse Gas Cap-and-Trade Program under title 17, Cal. Code of Regs. article 5, and by doing so, I am now subject to all regulatory requirements and enforcement mechanisms of this voluntary renewable energy set-aside program and subject myself to the jurisdiction of California as the exclusive venue to resolve any and all disputes.”
(c) “Number of MT CO_2e” rounded up to the nearest whole ton, is the number of allowances to be retired from the Voluntary Renewable Electricity Reserve Account; (REMA2)

Response: It is our intent to require direct delivery of the electricity. We clarified in section 95841.1(b)(2) and (3) to report just the megawatt-hours and RECs designated for use toward the allowance retirement, not all electricity or RECs generated by the facility. We clarified in section 95841.1(b)(1) that the attestations apply to the requirements of the VRE program, rather than the entire regulation. We do not agree the tons should be rounded up but rather rounded down. This will preserve the allowances available for other participants to request allowance retirement.

I-103. Comment: Section 95841.1 Voluntary Renewable Electricity (b)(1)(A) Report to ARB the quantity of renewable electricity in MWhs, and/or the number of RECs generated during the previous year from ~~an eligible~~ renewable electricity ~~generator~~ generation that meets the requirements of section 94841.1(b)(~~3~~2) or (~~4~~3), as applicable.

The Utilities continue to believe that the goals of AB 32 would be better served by deferring the initiation of a voluntary renewable electricity (VRE) market until both the 33 percent RPS and the Cap and Trade programs have had time to develop. The Utilities are concerned that this VRE market will act in direct competition with the 33 percent RPS market, constraining all electric distribution utilities in their effort to comply with their compliance obligations under both the RPS and the Cap and Trade. The above suggested corrections are necessary to ensure that this section of the RPR is internally consistent. First, section 94841.1(b) does not include any subsection (4).

By the context of the section the Utilities believe the references were intended to be covered as indicated. The referenced subsections use the term "renewable electricity generation from an eligible facility." The Utilities provide this mark up to avoid the confusion created by inconsistent terminology. Moreover, the RPS does not include any definition of eligible renewable electricity generator. Modify section 95841.1(b)(1)(A) as follows:

> (A) Report to ARB the quantity of renewable electricity in MWhs, and/or the number of RECs generated during the previous year from ~~an eligible~~ renewable electricity ~~generator~~ generation that meets the requirements of section 94841.1(b)(~~3~~2) or (~~4~~3), as applicable. (MID3)

> **Response:** We corrected the references in section 95841.1(b). We do not agree with this proposed change regarding eligibility. We believe the generation should meet certain eligibility requirements. These requirements ensure that the generation is actually occurring and that the generator has met certain requirements established by the CEC.

I-104. Comment: The Utilities provide the following typographical correction.

(b)(3) VRE Participants seeking allowance retirement for renewable electricity ~~generating~~ generation from an eligible facility… (MID3)

> **Response:** We thank the Utilities and corrected the typographical error.

I-105. Comment: Given ARB's recent elimination of the allowance distribution and compliance obligation for 2012, 3Degrees recommends that ARB modify section 95841.1(a) as follows:

> (a) Program Requirements: The end-user, or VRE participant acting on behalf of the end user, must meet the requirements of this section. Generation must be new and not have served load prior to July 1, 2005. Allowance retirement for purposes of voluntary renewable electricity will begin in ~~2013~~ 2014 for ~~2012~~ 2013 generation. Eligible renewable electricity, or renewable electricity associated with RECs, must provide direct delivery of electricity to California. (3DEGREES2)

> **Response:** We agree and incorporated this change into section 95841.1(a).

I-106. (multiple comments)

Comment: It appears there is an incorrect reference in section 95841.1. To allow for the use of industry standard renewable energy tracking systems and reporting documentation, 3Degrees suggests amending sections 95841.1 (b)(1)(C) and (b)(1)(D). The attestation is unclear on what is meant by "any claims for electricity", leaving room for unwanted interpretation. 3Degrees recommends amending the attestation. Sections 95841.1(b)(2)(A) and (b)(3)(B) are slightly unclear what exact piece of information ARB is seeking. 3Degrees suggests amending the language. The requirements in sections 95841.1(b)(2)(B), (b)(2)(C), (b)(3)(C), and (b)(3)(D) could be interpreted as requiring the VRE participant to submit information on the total MWhs and RECs generated by the facility, as opposed to just the MWhs or RECs for which the VRE participant is seeking allowance retirement. As it is often impossible for a REC purchaser to know total generation if the purchaser bought the REC from an entity other than the generator, 3Degrees believes ARB's intent is to require only the latter. 3Degrees recommends ARB clarify its intent by appending the sentences. Modify section 95841.1(b) as follows:

(b) Reporting Requirements. The end-user, or the VRE participant acting on behalf of the end-user, requesting allowance retirement for eligible generation must meet the following requirements for the period in which allowance retirement is being requested:
(1) By July 1 of each year, provide a written request for allowance retirement for the previous year's generation or REC purchases. Request must be accompanied by the requirements below:

(A) Report to ARB the quantity of renewable electricity in MWhs, and/or the number of RECs generated during the previous year from an eligible renewable electricity generator that meets the requirements of section 95841.1(b)(~~3~~ 2) or (~~4~~ 3), as applicable;
(B) Generator of the renewable electricity or RECs must be certified as RPS eligible by the California Energy Commission;
(C) Contract or settlement, or renewable energy tracking system data for the purchase of the electricity or RECs associated with the generation of the electricity;
(D) Contract or settlement or renewable energy tracking system data for sale of the electricity or RECs associated with the generation of the electricity to the end-user or entity purchasing on behalf of the end-user; and
(E) Attestations:

1. Attest, in writing, to ARB as follows: "I certify under penalty of perjury of the laws of the State of California that I have not authorized use of, or sold, any renewable electricity credits or any claims to the emissions, or lack of emissions for electricity for which I am seeking ARB allowance retirement, in any other voluntary or mandatory program."

(2) VRE Participants seeking allowance retirement for renewable electricity generation from an eligible facility > 200 KW nameplate capacity must submit the following with the report required in this section:

(A) Provide the generator's RPS ~~generator~~ certification identification number, as determined by the California Energy Commission;
(B) MWhs of renewable electricity generated for which the VRE participant is seeking allowance retirement;
(C) Number of RECs, as applicable for which the VRE participant is seeking allowance retirement; and
(D) REC retirement report.

(3) VRE participants seeking allowance retirement for renewable electricity generating from an eligible facility ≤ 200 KW nameplate capacity must submit the following with the report required in this section:

(A) Application must be for retirement of more than an equivalent of 150 metric tons CO_2e. Applicants may aggregate eligible systems to meet this threshold requirement, but must submit only one application under one entity;

(B) Provide the generator's RPS ~~generator~~ certification identification number, as determined by the California Energy Commission;

(C) MWhs of renewable electricity generated for which the VRE participant is seeking allowance retirement;

(D) Number of RECs, as applicable for which the VRE participant is seeking allowance retirement; and

(E) REC retirement report. (3DEGREES2)

Comment: Section 95841.1(d) introduces a potential voluntary renewable electricity tracking system as a way to show that the requirements of 95841.1(b) are met. WREGIS, an existing renewable energy tracking system, could be used as opposed to creating a separate tracking system specifically for the voluntary market. WREGIS is currently used by CEC, as well as other state programs, to verify REC ownership for RPS compliance. WREGIS can incorporate a function in which the certificates can be retired into accounts specifically for the voluntary renewable energy set aside. This would cost considerably less than developing an entirely new tracking system, and provide the same functionality needed for the set aside. Although the use of a tracking system will help meet a majority of the requirements of 95841.1(b) more efficiently and effectively, the tracking system should not be used in lieu of all requirements. The reporting requirements in Section 95841.1(b)(1)(D), regarding the contract or settlement data for the sale of the electricity or RECs, should still be required as this information cannot be reported in a tracking system.

Section 95841.1(b)(1)(D) requires requests for allowance retirement to be accompanied by "contract or settlement data for sale of the electricity or RECs associated with the generation of the electricity to the end-user or entity purchasing on behalf of the end-user." CRS requests feedback on what level of data is needed for reporting purposes, and whether the data submitted by market participants will have to be vetted by a third party. Many renewable energy marketers have a large number of customers and hence a great deal of contracts. Requiring the reporting of data on each individual contract would be time-consuming and cumbersome to both the party seeking allowance retirement and to CARB staff. Furthermore, many utilities offer green pricing programs where an official contract is not available, as the voluntary purchase of renewable electricity or RECs is simply a line item on a utility bill. In lieu of reporting all individual contracts, market participants should be able to submit aggregated sales records containing the total quantity of renewable electricity or RECs sold into the voluntary market, so long as the data is supported by an independent audit. The auditor should sample all individual contracts and sales records to confirm that the information reported is accurate. Furthermore, should CARB require the reporting of individual records, CRS recommends that names of customers not be disclosed on any publicly available documents. This ensures privacy for the renewable electricity and REC purchasers, and eases the concerns of competitive suppliers of losing their purchasers to other market sellers. (CRS2)

Comment: Incorporating tracking system data in ARB's reporting requirements, both for direct retirement of RECs and retirements on behalf of an end user, would encourage the set-aside's efficient operation and oversight. The use of a tracking system, like the Western Renewable Energy Generation Information System (WREGIS), enables easy and accurate REC retirement reporting, reducing the verification workload for ARB staff and the need for private companies and individuals to adopt new systems to participate in the state's GHG reduction efforts. REMA recommends that ARB revise the VRE set-aside reporting requirements to allow for the use of existing reporting pathways. Modify sections 95841.1(b)(1)(D), (b)(2)(D), and (b)(3)(E) as follows:

(D) Contract, settlement, or tracking system data for sale of the electricity or RECs associated with the generation of the electricity to the end-user or entity purchasing on behalf of the end-user; and

(D) REC retirement report or tracking system data.

(E) REC retirement report or tracking system data. (REMA2)

> **Response:** The commenters above request changes to the requirements for documenting purchase and sale of renewable electricity and RECs, which are needed to prevent, to the extent possible, the double-counting of a zero-GHG emission attribute of the renewable energy. We agree to add "tracking system data" as requested, to sections now renumbered as sections 95841.1(b)(1)(D), (b)(1)(E), (b)(2)(D), and (b)(3)(D) because some eligible VRE electricity is not associated with an REC. For example, an entity may install a 10 KW photovoltaic system but not register with WREGIS or another REC-creating program due to cost, but the generation is still voluntary renewable electricity to meet the requirement contained in section 95841.1(b).
>
> We agree with the 3DEGREES2 comment regarding the first attestation and modified section 95841.1(b)(1)(E) (now F) as requested. We also modified sections 95841.1(b)(2)(A) and (b)(3)(B) as requested to clarify that we are seeking the CEC's RPS certification ID number. In addition, we modified old sections 95841.1(b)(2)(B), (b)(2)(C), (b)(3)(C), and (b)(3)(D) to clarify that participants must report electricity generated and designated for VRE retirement, and RECs designated for VRE retirement as applicable, meeting the intent of 3DEGREES2 requested modification.
>
> CRS2 comments that WREGIS could be used for tracking RECs in the voluntary market. We appreciate this suggestion and allow REC retirement reports from WREGIS to be used to verify REC retirement. We do not agree that information about contract or settlement data on sales of electricity cannot be reported in a tracking system. For example, a utility may use a tracking system that could

provide data for electricity sold to customers as part of a "Green Energy" program.

CRS2 also asks about the level of data needed for reporting data associated with the sale of electricity or associated emissions. It is important to have verifiable data on all sales of electricity and RECs to prevent double-counting. By adding tracking system data as an alternative for documenting sales, we believe we met the commenter's concern. We note that all required reports and data are subject to ARB verification.

I-107. Comment: Section 95841.1(a) requires that voluntary renewable electricity be generated from facilities that came online after July 1, 2005. The voluntary renewable energy market is a national market with an established 15-year rolling online date. By disallowing California facilities with online dates prior to 2005 to qualify for the voluntary renewable energy set aside, many generators based in California would be excluded from participating in this national market. Section 95841.1 already prescribes eligibility criteria for generation that can qualify for allowance retirement as requiring the generators be certified as RPS eligible by CEC. CRS suggests not setting an arbitrary new date that puts California capacity at a competitive disadvantage compared to the rest of the U.S. If CARB moves forward with the 2005 date, REC providers both in California and nationally would turn to out-of-state RECs for their green power products, and the role of California generators in this market would be diminished. This would particularly impact California utilities that offer their customers green electricity, as they tend to own their own generation capacity or buy renewable energy generated within the state. (CRS2)

Response: We do not agree with the proposed on-line date. The July 2005 date coincides with the release of Governor Schwarzenegger's Executive Order S-3-05, which established the climate change emission-reduction targets for California. In addition, we want to ensure that the generation that is supplying the voluntary sector and that results in allowance retirement is efficient and representative of technology approved by the CEC. This date ensures this intent. In addition, to be eligible for the RPS, out-of-state facilities must have come on-line in 2005 or later.

I-108. Comment: Section 95841.1(b)(1)(E)(1) requires voluntary renewable energy market participants to attest that they "have not authorized use of, or sold, any renewable electricity credits or any claims for electricity… in any other voluntary or mandatory program" for which they are seeking allowance retirement. Such an attestation is unsuitable for the voluntary renewable energy market, as claims to zero-emissions electricity are precisely what REC and renewable electricity providers are selling to their customers. Ownership of a REC or renewable electricity entitles the purchaser to make statements surrounding their emissions-free electricity use. It is also commonplace and encouraged for these purchasers to participate in other programs. As currently written, the attestation in this section suggests that the voluntary renewable energy participant is the entity making the claim, whereas most of the time this is not the case. Rather, the voluntary renewable energy market participant is selling the claim to the end-user, or renewable energy purchaser, and seeking allowance retirement on their behalf. CRS understands the intent of this language is to prevent the double counting of renewable energy, and not retire allowances on behalf of renewable energy that is being double sold. However, as currently written, market participants would have difficulty signing such an attestation. CRS recommends changing the attestation to clarify that the renewable energy or REC end user is allowed to make a claim and participate in voluntary programs that recognize renewable energy purchasing. One suggestion is to insert “to any party other than the renewable energy purchaser” after “claims of electricity” in the section in question. With this modification, the attestation would read “I certify under penalty of perjury of the laws of the State of California that I have not authorized use of, or sold, any claims for electricity to any party other than the renewable energy purchaser for which I am seeking ARB allowance retirement, in any other voluntary or mandatory program.” (CRS2)

> **Response:** The change recommended to section 95841.1(b)(1)(E)(1) would defeat the purpose of that section. For example, if a marketer sold claims or an REC to an end user, that end user could then use the REC in another jurisdiction, or sell the REC to a third party for use in another jurisdiction. If an REC or other claim is used to retire allowances, it must not be used in any other program to prohibit, to the extent possible, double-counting.

I-109. Comment: Sections 95481.1(b)(2)(D) and 95481.1(b)(3)(E) require "REC retirement reports" to be submitted by voluntary renewable energy participants seeking allowance retirement. While electronic tracking systems are the preferred means for showing REC retirement, they can be cost-prohibitive to generators below a certain size. CRS recommends that for generators below 10 MW, an attestation be allowed in lieu of a retirement report from a tracking system. This attestation should state that the market participant has ownership of the renewable energy generation, and that they have not sold the renewable energy attributes separately to other customers or used it to make other renewable energy claims. (CRS2)

> **Response:** We do not agree with CRS that systems below 10 MW should rely solely on an attestation to demonstrate a REC has been retired. If an REC is created for a megawatt-hour of renewable electricity, it must be retired so that it cannot be used to support a claim in another program. We added an option to submit tracking system data that should address the cost concern for smaller systems. This has been included in modifications to sections 95841.1(b)(1), (b)(2) and (b)(3).

I-110. Comment: Section 95841.1(c) requires use of the default emission factor for unspecified power when calculating the amount of allowances to be retired for the voluntary set aside. A more widely accepted rate for determining the equivalent emissions avoided from renewable energy generation is use of the non-baseload output emission rate, employed by the U.S. EPA Green Power Partnership and by

Green-e Energy. The Regional Greenhouse Gas Initiative (RGGI) also recommends using the marginal rate of electricity generation when available to calculate the amount of allowances to retire on behalf of the voluntary renewable energy market. The default emission factor recommended by CARB is closer to a system average, which does not take into account the true effects of renewable energy generation on the grid, which generally is to back down plants operating on the margin. Since it is more accurate, the number of allowances to be retired on behalf of voluntary renewable energy would ideally be calculated using the non-baseload output emission rate.

To avoid double counting, imports of underlying electricity of renewable energy generation that has been stripped of its RECs would be assigned the emissions equivalent to the non-baseload output emission rate. CRS realizes that it is more likely that if imports of renewable energy generation absent RECs were to be assigned emissions as unspecified power, they would be assigned the default emissions rate. Thus, for consistency, CRS finds it sufficient that the default emission rate is also used for calculating the number of allowances to retire for the voluntary set aside. (CRS2)

> **Response:** We acknowledge CRS identification of the use of emission rates used in other programs such as the U.S. EPA's Green Power Partnership, which uses eGrid for applicable emission rates. In the future, we will consider the use of non-baseload output emission rates as determined by the eGRID data and propose changes, if needed. We are evaluating the underlying data used by eGRID and the implications of using the four emission rates calculated for the subregions identified for the WECC. We do not anticipate the need to assign any default factor to power that has been stripped of its REC. We included requirements into sections 95841.1 and 95852(b) to ensure there is no double-counting of emission attributes, and therefore no need to assign an emission factor to the null power.

I-111. Comment: The ARB proposal includes a "voluntary renewable energy program" (Proposed section 95841.1) that will retire GHG allowances (up to a cap) to reflect the GHG-reducing effect of consumers voluntarily purchasing renewable energy in excess of what is required under California's Renewables Portfolio Standard (RPS) statutes. Properly structured, this provision supports electric distribution utilities, CCAs, energy service providers and other entities that provide electricity supplies that exceed state mandates for renewable content. CCSF supports this proposal, but notes some inconsistencies in the proposal as written. For example, although described in the 15-day notice as promoting the use of voluntary "renewable energy, (i.e. energy that "is not the subject of a mandate") the definitions section of the proposal ((section 95802(a)(280)) defines "Voluntary Renewable Electricity" as renewable energy "which will not be used to meet any other mandatory requirements or voluntary program." CCSF recommends that ARB continue to work with stakeholders, such as end-users and entities acting on their behalf, to ensure that the implementing Regulations work together with existing and proposed RPS regulations and reporting protocols. CCSF looks forward to working further with ARB on this program. (SFMAYOR3)

Response: We acknowledge CCSF's support of the voluntary renewable electricity budget adjustment. We include the requirement that the eligible renewable electricity for which an allowance will be retired is not claimed within any other program to prevent the double-counting of zero-emission electricity, or the double-counting of the "lack of emissions" attributed to this electricity. The regulation contains direct and explicit language that is more precise than the notice, and provides a clear definition.

I-112. (multiple comments)
Comment: LADWP supports voluntary renewable energy (VRE). However, it is unclear whether the amount of allowances set-aside is consistent with forecasts for participation in VRE. LADWP recommends that ARB retain the option for the Executive Officer to transfer unused allowances under extreme circumstances when the supply of compliance instruments is severely depleted. Modify section 95831(b)(6) as follows:

(6) Reserve account for Voluntary Renewable Energy Allowance Electricity Set-Aside Account. A holding account to be known as the Voluntary Renewable' Electricity Reserve Account, which will be closed when it is depleted of the following originally allocated allowances:

(A) Into which the Executive Officer will transfer allowances allocated pursuant to section 95870(c); and

(B) From which the Executive Officer may retire allowances pursuant to section 95841.1.

<u>(C) From which the Executive Officer may transfer allowances to the Auction Holding Account if it is determined 1) the Allowance Containment Reserve has been depleted, and 2) participation by VRE participants is less than the original forecast.</u> (LADWP4)

Comment: The Modified Text provides, for the first time, definitions and explanations regarding that aspect of the Cap and Trade Program that will allow entities to voluntarily retire GHG compliance instruments associated to the production of renewable electricity not used to meet the requirements of any other state programs (see sections 95802(a)(279), 95802(a)(280), and 95802(a)(281)). NCPA strongly encourages CARB to include provisions within this section for annual review of the set-aside amounts. It is a laudable goal for entities to seek out renewable electricity contracts in excess of the statewide mandate, and seek to purchase and retire GHG allowances associated with that renewable electricity. However, those worthy objectives do not come without a cost, one that is likely to be felt by all California electricity customers. That is because as the statewide mandate for renewable electricity increases, so does the demand for such renewable resources. Those that are financially able to acquire the renewable resources will drive up the price, at the expense of the utilities that are constrained by legislation to acquire the resources in a cost-effective manner. Furthermore, even when the number of allowances that are set-aside for retirement of voluntary renewable electricity is small, the action results in fewer allowances being available to entities that need them to meet a mandatory compliance obligation. When considered collectively, the number of allowances that can be set-aside or removed from the market for voluntary retirement has a cumulative impact on all compliance entities. Therefore, NCPA urges staff to revise these provisions to reduce the total number of allowances that are set aside for the VRE program, and to mandate an annual review of the set aside to determine the impact the program is having, if any, on the availability and cost of allowances for compliance entities. Modify sections 95870(c) and 95841.1(f) as follows:

> (c) Recognition of Voluntary Renewable Electricity Emissions Reductions. On December 15, 2012, the Executive Officer shall transfer allowances to the Voluntary Renewable Electricity Reserve Account, as follows:
>
> > ~~(1) 0.5~~ 0.25 percent of the allowances from budget years 2013-~~2014; and~~
> > ~~(2) 0.25 percent of the allowances from budget years 2015-~~2020.

<u>(f) Beginning on January 1, 2014, and annually thereafter, the Executive NCPA Officer Staff shall conduct a review of the this section 95841.1 to determine its impact on the availability and cost of allowances in the auctions during the preceding year, and if it is determined that the provisions of this section have adversely impacted the ability of compliance entities to meet their compliance obligations under the Program, the Executive Officer shall recommend to the Board corrective actions necessary to address the adverse impacts.</u> (NCPA3)

> **Response:** We do not agree. The number of allowances placed into the VRE account is based on the demand for voluntary renewable electricity at the same growth rate for the years 2006 through 2008. We expect supply to meet the demand, and as a consequence it is possibly more likely there will be an insufficient number of allowances to cover all requests for this transitional program.

I-113. (multiple comments)
Comment: CRS is pleased to see the inclusion of a set aside for the voluntary renewable energy market, and commends CARB for allowing voluntary purchasers of renewable energy to continue to reduce GHG emissions. This provision will further stimulate renewable energy growth in California, thus promoting job creation and reducing GHG emissions beyond the level set by the cap. (CRS2)

Comment: We would like to add our support for the Cap and Trade programs provision for voluntary renewable energy markets. Providing an accounting mechanism for voluntary renewable energy within the cap and trade program is critical to the future viability of this market. (NEXTERAENERGY2)

> **Response:** We thank the commenters for their support of the VRE program.

I-114. Comment: Small renewable energy generation, whether hosted by a single residential/commercial entity or a collection of entities, will aid the State's GHG reduction goals. However, the requirements for ≤ 200 kW nameplate capacity described in section 95841.1(b)(3) risk deterring small-scale participation. The minimum allowance application level of 150 $MTCO_2e$ is too high for most residential and small commercial entities to meet alone, and REMA believes the likelihood of aggregation among disparate entities is low. Decreasing the threshold below 150 $MTCO_2e$ (to a to-be-determined limit) should increase residential and small commercial access to allowances. REMA recommends that ARB, in conference with small-scale renewable generation partners, propose a more realistic and attainable $MTCO_2e$ limit. (REMA2)

> **Response:** We agree and removed the requirement to aggregate from section 95841.1(b)(3). We will still allow aggregation, if applicants choose to do so, but it is no longer a requirement.

I-115. Comment: CAPCOA recommends that Voluntary Renewable Electricity Allowances (VREA) should be preferably awarded to those projects which are "additional" and would not have happened under baseline business as usual conditions without the GHG value of the allowance. The VREA pool should be large enough and have sufficient flexibility to stimulate "additional" renewable energy projects. This may need to be more than the 0.5 percent proposed allotment. (CAPCOA2)

> **Response:** We disagree with CAPCOA in that the allowances should be awarded to projects that are "additional" and would not have happened under baseline BAU conditions without the GHG value of the allowances. No value will be transferred by the voluntary renewable electricity budget adjustment. We will retire the allowances based upon applicants providing required information on contributions of eligible generation. As long as a cap is in place and these generators are providing electricity for the voluntary market, then these contributions are helping to meet the cap. In order for this market to continue to make the marketing claim that the electricity "reduces GHGs" the allowances must be retired. We estimated the demand for 2007 through 2009 and are including a sufficient number of allowances to cover the expected demand at current growth rates. Once the program has been fully subscribed, then the voluntary market will need to register in our program as a voluntarily associated entity, and must purchase and retire allowances to continue to make their claim that the voluntary contributions reduce GHGs in California.

I-116. (multiple comments)
Comment: The definition of "Voluntary Renewable Electricity" in section 95802(a)(280) contains a reference to renewable energy certificates (REC) being applied towards mandatory and voluntary programs in California. REMA recommends that ARB clarify the definition by removing the reference to "voluntary programs," as it may create confusion and appear to prevent voluntary renewable energy purchasers from participating in recognition programs and other voluntary programs, such as the U.S. Environmental Protection Agency's (EPA) Green Power Partnership program. (REMA2)

Comment: In section 95802(a)(280), the first clause of the definition for "Voluntary Renewable Electricity" is slightly confusing and refers to RECs as REDs. Also, the use of "voluntary program" in this context creates some confusion. Renewable electricity and RECs purchases are reported by voluntary consumers in voluntary recognition programs, such as the U.S. Environmental Protection Agency's Green Power Partnership. As written, this definition would appear to prohibit this sort of activity. Modify section 95802(a)(207) as follows:

(207) "Voluntary Renewable Electricity" or 'VRE' means electricity ~~produced or REDs associated with~~ or RECs associated with electricity, produced by a voluntary renewable electricity generator, and which ~~will~~ has not and will not be sold or used to meet any other mandatory requirements ~~or voluntary program~~ in California or any other jurisdiction. (3DEGREES2)

> **Response:** We agree with 3DEGREES and corrected the typographical error in the definition for "Voluntary Renewable Electricity." We agree with 3DEGREES that participants should be allowed to participate in other voluntary recognition programs. See the response above to REMA2.
>
> We agree that we do not want to prevent participants from being able to participate in other voluntary recognition programs so long as it is the same entity that holds the right to the claim. It is not our intent to have allowances retired from this program and have the participant also make GHG emission-reduction claims in other programs for the same reductions already claimed in our program. We modified the definition in section 95802, but we point out to the commenter that no other claims may be made for the lack of emissions, and this is ensured by the attestations and retirement reports and tracking system data that must be submitted with the application and are subject to verification by ARB.

Combined Heat and Power (CHP)

Incentives and Inequity Between Sources Above and Below 25,000 $MTCO_2e$/year

I-117. (multiple comments)
Comment: Due to the design of California's Cap and Trade Regulation, the treatment of CHP facilities under the Regulation is not immediately obvious, which has resulted in confusion among owners and operators of facilities trying to interpret how the regulation impacts their operations. The Regulation includes in the list of "covered entities" operators of facilities with a cogeneration process, but allocates allowances based upon industrial sectors and leakage risk, not specifically the facility processes. A CHP facility may provide the thermal and retail electricity at one of these industrial sites, or at a commercial or institutional location that has not been identified as being at risk of leakage. Consequently the economic impact of the regulation, as currently designed, may affect operators of CHP facilities differently, based upon a range of circumstances. As a result of allocating allowances to the industrial sector, and not the load, the regulations may discourage installation of CHP at some locations. Some CCC members are concerned that the complexity of the regulation and the requirement to

participate in auctions will result in costly administrative overhead and uncertainty, particularly for some of the smaller CHP operators who are required to participate.

BE IT FURTHER RESOLVED that the Board directs the Executive Officer to review the treatment of combined heat and power facilities in the cap-and-trade program to ensure that appropriate incentives are being provided for increased use of efficient combined heat and power.

The CCC is concerned that not only does the modified Regulation not, "ensure appropriate incentives," but it in fact penalizes some early adopters of CHP. The treatment of CHP facilities under the regulation is an issue of significant importance as CCC members evaluate the regulatory landscape of California, and consider their options under the CHP Program Settlement Agreement. These options include whether to continue operations in California and seek new contracts for existing facilities, sign contract amendments adopting an energy payment calculation based on perceived exposure to GHG risk, repower existing facilities, and develop new projects. It has been our hope that the new CHP State Program, which is a result of the Settlement, and is structured around the ARB Scoping Plan CHP Emissions Reduction Measure, will encourage investment in upgrading facilities and spur the development of new facilities. Our fear is that the Regulation, as currently designed, does the opposite. (CACC2)

Comment: The AB 32 Cap and Trade program as currently constituted inhibits the development of new CHP. Whether a facility is benchmarked in terms of tonnes of CO_2 emissions/ton of output or tonnes of CO_2 emissions/energy used (MMBtu), the facility's emissions and compliance obligation would increase with the installation of a new CHP plant without a concomitant increase in either production or energy use. However, CHP installation results in more efficient production of the energy consumed by the facility and a net reduction in societal greenhouse gas emissions. IEA respectfully requests that ARB place a high priority on adopting positive incentive measures that can be used to meets the board's stated program goals and promote CHP in the following ways:

- Support for the Self-Generation Incentive Program (SGIP).
- Free allowances to cover carbon emissions from CHP installations.
- Credit mechanisms both for early, ongoing and future actions related to CHP.
- Exemption from a compliance obligation for facilities whose CO_2e emissions would not exceed the 25,000 tonnes/year threshold but for the existence, expansion or new installation of a CHP plant.

We urge CARB to further explore these options and to closely coordinate with the Public Utilities Commission on the potential to set aside allowances for CHP operators for the net greenhouse gas emissions reductions on the California grid resulting in a power production offset by the CHP installation. (INDENVASSOC2)

Comment: A commercial/industrial customer should not be bumped over the Cap and Trade threshold of 25,000 $MTCO_2e$ because of clean onsite CHP. A four to five MW CHP system can trigger the 25,000 $MTCO_2e$ threshold even if there are no other GHG emission sources onsite. As most sites will already have some level of natural gas use, the threshold could be reached with CHP systems much smaller than four MW. CHP, through its greater than 60 percent efficiency and displacement of base-load natural gas generation, reduces total systems emissions, a positive societal benefit. However, the host's direct emissions will increase from power production on-site and, as a result, its carbon cost exposure. The owner of an existing system may choose to shut down its system. We understand the Industrial Environmental Association will provide specific examples of this occurrence. For customers considering new CHP, the cost exposure would be a deterrent to installing such clean, efficient systems because of the cost and complexity of obtaining carbon allowances and the extra scrutiny, monitoring and reporting that will be required. CHP is rightfully recognized as a cost-effective tool to meet GHG reduction goals and one that also contributes to increasing system efficiency, reliability and resiliency. We strongly recommend that CARB further study a "but-for" CHP case where such customers are exempt from Cap and Trade, or are able to receive free allowances. (CACDGC2)

Comment: Section 95811 identifies the entities to which the Regulation applies, and section 95812 describes the inclusion thresholds for covered entities. For the operator of a cogeneration facility, the applicability threshold is 25,000 metric tons or more of CO_2e per data year. For a CHP facility the total emissions can consist of the emissions associated with three separate products:

(i) Wholesale electricity,
(ii) Thermal energy, and
(iii) Retail electricity.

Collectively, if the emissions from all three energy products exceed the 25,000 metric tons, then the CHP facility is included under both the Mandatory Reporting Regulations and the Cap and Trade Regulation. The Regulation also states that at the start of the second compliance period in 2015, the natural gas sector will be covered by the Regulation. This means that those facilities that combust natural gas, but are currently below the applicability threshold, will face costs beginning in 2015 for the associated emissions because suppliers of natural gas will have a compliance obligation in the second compliance period. Consequently, in the first compliance period, except in the case of a facility that is an opt-in covered entity pursuant to section 95813, facilities that use boilers instead of CHP, for which total emissions associated with the facility are less than the 25,000 metric ton threshold, have no compliance obligation. However, a CHP facility where the emissions associated with the thermal energy are less than 25,000 metric tons, does have a compliance obligation in the first compliance period. This unequal treatment highlights the issue CCC and many other CHP advocates raised with the regulatory agencies when development of the Cap and Trade Regulation first began. Even though the installation and operation of efficient CHP results in less overall emissions than compared to the alternative, i.e. a standalone boiler and electricity from the grid, the CHP facility is responsible for more onsite emissions than just the boiler, and consequently will end up with a greater compliance obligation, if the policy rules are not carefully designed. In this situation an early adopter of CHP is actually penalized for using CHP instead of a boiler because the CHP facility bears a compliance obligation in 2013 and 2014, while the site with the boiler does not. In order to ensure equal treatment, the CCC recommends that where onsite CHP results in emissions greater than the applicable threshold as compared to using a boiler to provide steam needs, and the total emissions of the facility, but for CHP would be less than the 25,000 metric tons threshold, the emissions associated with the steam should be exempt from the facility's compliance obligation until the second compliance period when natural gas is included in the Cap and Trade program. An indirect consequence of this exemption for the first compliance period may be the resolution of some portion of legacy steam agreements. ARB staff should review their database of legacy steam agreements applying this proposed threshold exemption, which is approximately 376,923 MMBtu of steam in an 80 percent efficient boiler. Modify section 95812 as follows:

> (c) The requirements apply as follows:
>
> > (1) Operators of Facilities. The applicability threshold for a facility is 25,000 metric tons or more of CO_2e per data year. <u>In the case of a cogeneration facility where the emissions associated with the useful thermal energy are below the threshold of 25,000 metric tons of CO2e per data year, and in the absence of the cogeneration facility there would be no compliance obligation, the emissions attributable to the thermal energy from that facility will not be included in the covered entity's compliance obligation in years2013 and 2014.</u> (CACC2)

> **Response:** We disagree and believe the price signal created by the program incentivizes high-efficiency steam and electricity generation technology such as CHP. We understand the inequity between facilities emitting less than 25,000 $MTCO_2$e and those emitting greater than 25,000 $MTCO_2$e, but this inequity will only exist in the first compliance period: 2013 and 2014. Beginning in 2015, all fuels will be included in the cap-and-trade program, and all facilities will then share a similar price signal.

Existing Contracts

I-118. Comment: The design of the Cap and Trade Regulation is predicated on the assumption that carbon costs will be borne by the end user / consumer through appropriate pricing of the "product" produced by covered entities, but this will not be the case where contractual agreements do not contain a cost recovery provision. The CCC recognizes that there are several types of legacy contracts that do not provide for GHG cost recovery. There may be more, but those brought to our attention include,

1. Power Purchase Agreement (PPA) between generator and utility,
2. Steam (and in some cases retail electricity) agreement, between a CHP facility and thermal host,
3. Tolling agreement between a generator and a utility,
4. Agreement between a generator and a marketer selling power into the electricity market.

Our specific issue concerns CHP projects with agreements in #2 above. In most cases, these agreements run in parallel with the facility's utility PPA, and consequently were signed many years prior to the passage of AB 32. Under the Regulation, the Operators of such CHP facilities face stranded costs in terms of the emissions associated with the thermal, and in some cases retail electricity production of the facility, until the expiration of these agreements. This issue is not limited to CHP in industrial sectors that may be receiving an allocation of free allowances based on product or energy use benchmarks. Legacy contracts also exist in non-leakage exposed sectors, for example, universities and prisons, and the Buyer of the CHP energy is not a covered entity under the Regulation. These and other CHP facilities were developed in the 1980s in response to federal and State energy policies designed to encourage increased installation and operation of CHP. New state regulations should not be structured in such a way as to undermine those existing contracts as this will send the wrong signal to investors considering new development of efficient CHP, and modification to existing facilities. There does not appear to be a universal solution that will resolve this problem. However, this may be a transition issue. When the commercial agreement between Buyer and Seller expires, surely any new agreement will include carbon cost recovery provisions. A significant number of CHP QF PPAs will be expiring in the next five years, which seems to imply the pool of affected projects with this specific legacy contract issue may reduce in size in the near future. The CCC recommends that ARB staff continue to evaluate each legacy contract on a case by case basis and provide some sort of special treatment. This may involve an allocation of free allowances, or perhaps an exemption from the Regulation for a period of time. The reference point for staff in considering solutions should be Resolution 10-42, i.e. the Regulation should include appropriate incentives for increased use of efficient combined heat and power. Leaving these facilities to face stranded costs will be a disincentive to continued operation, particularly at those sites where owners were previously planning to make considerable investment to repower their existing facilities. (CACC2)

> **Response:** We realize that a portion of generators and industrial steam producers have reported that some existing contracts do not include provisions that would allow full pass-through of carbon costs associated with cap-and-trade. We closely examined this issue, but do not believe it is the role of the regulator to negotiate contracts for parties engaged in an agreement, nor will we treat entities differently who do have negotiated contracts. In several cases, we are aware and encouraged by knowledge of parties that are in the process of, or already have, negotiated new contracts to resolve this issue. We believe that bilateral contract negotiations provide the best resolution to this issue.

Inequity of Grid and Direct Access

I-119. (multiple comments)
Comment: Most electricity consumed in the state is distributed through EDUs. A small portion of the state's electricity consumption occurs by ratepayers who obtain their electricity directly from a producer without going through an EDU. This is often an industrial electricity consumer obtaining power from a co-located but independent industrial cogeneration facility. CARB proposes to allocate allowances to EDUs based on the electricity consumption through their respective service franchises and then require these allowances to be auctioned with the proceeds being used for the benefit of their ratepayers. Since no allocations will be made to the "industrial cogeneration/distribution" entities delivering electricity directly to their rate-paying customers, there is an unequal (one-sided) opportunity to offer benefits to the ratepayer which favors the EDU. This will provide an incentive for current (and future) consumers of industrial cogenerated power to switch to grid-delivered power, a result contrary to CARB's policy objective of incentivizing cogeneration power. To prevent this unequal treatment, CARB must either allocate allowances to industrial cogeneration/distribution entities in a manner consistent with the proposed allocation to EDUs under section 95892, or revise the proposed regulations to require that cogeneration power customers receive the same benefits under section 95892(d)(3) as other EDU retail ratepayers. Providing allowance allocations where industrial cogeneration facilities directly deliver power to their customers is consistent with the "Criteria for Receiving Allowances as Part of the Electricity Sector Allocation" described in Appendix A of the 15-Day Modification package. Such industrial cogeneration power suppliers serve end-use customer's electricity load and receive payment for that load representing the same transactional relationship existing between EDUs and retail ratepayers. Allocation of allowances to qualifying industrial cogeneration facilities could be accomplished by classifying such electricity providers as a separate type of "distribution utility" and make allowance allocations to them consistent with the methodology described in Appendix A of the 15-Day Modification package. This includes employing the appropriate factors for the cost burden imposed upon ratepayers (footnote 10 of Appendix A). Allowances allocated in this manner would require comparable treatment to those allocated to EDUs —placement into a Limited Use Holding Account, sold at auction and benefit returned to the cogenerator's retail ratepayers consistent with section 95892(d)(3). Alternatively, the language of section 95892(d)(3) should be revised to clarify the industrial power customers of cogeneration facilities must receive "equal treatment" to EDU's own customers, just as "electricity service providers" and "community choice aggregators" are required to be treated equally to EDU customers. (APC2)

Comment: Free allowances ("Staff Proposal" for Allocating Allowances to the Electric Sector) could compromise CHP if offsetting GHG emissions at the CHP site and at the central power plant are not taken into account. The cost for natural gas directly consumed by CHP end users, including that for onsite CHP will carry a GHG charge (either directly or through the purchase of allowances). This will create a financial penalty for the CHP user relative to the avoided retail electric rate. The Staff Proposal appears to indicate that the financial penalty will be avoided: "Cost burden is expected to result from emissions costs associated with fossil, QF, and non-emitting resources priced at market being passed from generators and marketers to utility customers. …each utility can expect to be able to fully compensate their customers for the costs associated with the cap and trade program that are expected to be passed to customers" (section on Cost Burden). CCDC urges the Board to: recognize the offsets achieved by CHP for the avoided emissions from central station fossil plants; make clear that CHP be granted allowances equivalent to that provided to the utilities for fossil generation on a CO_2 per MWh basis, and transmit these findings to the PUC who we understand have been asked to address this issue in a rulemaking. (CACDGC2)

Comment: ARB should fairly allocate allowances for Combined Heat and Power (CHP) electricity production not distributed through an electrical distribution utility (EDU). ARB proposes to allocate allowances to EDUs based on the electricity consumption through their respective service franchises, and then require these allowances to be auctioned, with the proceeds being used for the benefit of their ratepayers. Since no allocation will be made to the "industrial cogeneration/distribution" entities delivering electricity directly to their rate paying customers, there is an unequal (one-sided) opportunity to offer benefits to the ratepayer which favors the EDU. This will provide an incentive for current (and future) consumers of industrial cogenerated power to switch to grid-delivered power—a result contrary to the Air Resources Board policy objective of incentivizing cogeneration of power. To prevent this unequal treatment, ARB must allocate allowances to industrial cogeneration/distribution entities in a manner consistent with the proposed allocation to EDUs under section 95892. Allocation of allowances to qualifying industrial cogeneration providers could be accomplished by classifying such electricity providers as a separate type of "distribution utility," make allowance allocations to them consistent with the methodology described in Appendix A of the 15-Day Modification package. This includes employing the appropriate factors for the cost burden imposed upon ratepayers (footnote 10 of Appendix A). Allowances allocated in this manner would require comparable treatment to those allocated to EDUs —placement into a Limited Use Holding Account, sold at auction, and benefit returned to their retail ratepayers consistent with section 95892(d)(2). (IGPACC)

Response: We agree that there should be equal treatment for both those that purchase electricity from the grid and those that purchase electricity from a local generator. To clarify, electricity utilities are allocated allowances to cover part of the total cost burden that AB 32 Scoping Plan measures add to the costs ultimately born by ratepayers. These costs include the relatively high costs of the 33 percent renewable portfolio standard, which is a cost that standalone generators are not subject to. Nonetheless, we are seeking equal treatment for those end users that bear the cost of the cap-and-trade program from indirect sources.

Currently, the California Public Utilities Commission (CPUC) proceeding is addressing utility costs and revenue issues associated with greenhouse gas emissions. Once the CPUC proceeding has concluded and we have determined to what degree facilities face the indirect carbon costs from purchased power that we expect will be embedded in utility rates, we will revisit this issue.

Contracts and Inequity of Grid and Direct Access

I-120. (multiple comments)
Comment: Although the AB32 Scoping Plan clearly acknowledged the benefits of efficient combined heat and power, and the ARB, in its December 16, 2010 Resolution 10-42, recommended that "treatment of combined heat and power facilities in the cap-and-trade program" be reviewed "to ensure that appropriate incentives are being provided for increased use of efficient combined heat and power.", there appears to be disparate treatment of CHP facilities with respect to allocation of allowances. We have legacy steam and electricity contracts, with both our industrial host and with the local utility. ARB has commented in workshops and other forums that it expects parties in a bilateral contract to work out the details of cost recovery between themselves. Although we are pursuing this approach with our industrial host, it still remains that the regulation, as crafted, may treat CHP facilities differently based on their ownership and which sectors they are included in. In our particular case, feeding a petroleum refinery, the refinery would be included in the list of industrial processes granted allowances based on being "Energy Intensive Trade-Exposed". If the refinery owned its cogeneration facility the GHG emissions from the cogeneration facility would be included in the total GHG emissions of the refinery. As it is now, the third-party cogeneration facility's GHG emissions are reported separately, and the facility is not allocated any allowances for providing electricity and useful thermal energy to the industrial process. We request that our specific case be evaluated with respect to allocation of allowances as a way of leveling the playing field for third-party owned CHP facilities. One obvious solution is to consider the power and thermal energy from a third-party cogeneration facility under the same sector rules as the end user, in this specific case petroleum refining. Alternatively, a recognized method for allowing pass-through of GHG costs to the final end user of the energy could have the same result. (MCLP)

Comment: The proposed 15-Day modifications fail to treat all obligated entities equally in regards to access to GHG compliance instruments. All independent power producers (IPP) are required to obtain their allowances via an auction. No free allowances are to be allocated, irrespective of the market/trade exposure faced by the individual generator. For a small subset of IPPs operating under existing, long-term contracts, currently no viable mechanisms exist within their contract structures to recover the cost of the GHG allowances they are obligated to obtain under the C&T program. This limited set of IPPs and combined-heat and power facilities ("CHP") operate under long term contracts. In order to avoid discriminatory impacts on the other 2 types of existing contracts without a reasonable means of cost recovery, IEP recommends inserting a new section in the regulation to deal with each of these transactions. IEP proposes the following addition, a new section 95871:

<u>This section applies to (1) electric wholesale CHP Facilities, without a means for GHG cost recovery, under a Long-Term Contract to a thermal host; and, (2) Electric</u>

wholesale generators, without a means for GHG cost recovery, under a Long-Term Contract with a Marketer.

a. CHP Facilities, without a means for GHG cost recovery, operating under a Long-Term Contract with a thermal host facility: In the event there is a Long-Term Contract for the sale of thermal energy which:

(1) does not directly or indirectly provide or refer to GHG costs; (2) was fully executed before the final approval of AB 32 (September 27, 2006); (3) has not been renegotiated as of January 1, 2012 to address GHG costs; and, (4) the CHP Facility has provided an annual attestation, backed by reporting data and a commercially binding agreement between the CHP Facility and the thermal host, that the agreement between the CHP Facility and the thermal host does not contemplate any compliance obligation by the thermal host, then:

i. The thermal host becomes the responsible entity for the GHG compliance costs associated with that contract until either (a) the contract term expires; or (b) the contract is renegotiated.
ii. The CHP Facility is relieved of its GHG compliance obligation associated with the emissions from that contract until (a) the contract term expires; or, (b) the contract is renegotiated between counterparties.

b. Electric wholesale generators, without a means for GHG cost recovery, under Long-Term Contract with a Marketer: In the event there is a Long-Term Contract for the sale of electricity at wholesale which:

(1) does not directly or indirectly provide or refer to GHG costs explicitly or alternatively through a CPUC approved contract or a CPUC authorized pricing basis that includes GHG costs; (2) was fully executed before the final approval of AB 32 (September 27, 2006); (3) has not been renegotiated as of January 1, 2012 to address GHG costs; and, (4) the electric wholesale generator has provided an annual attestation that there is a commercially binding agreement between the electric wholesale generator and the marketer, that does not contemplate any compliance obligation by the marketer, then:

i. The marketer in the transaction shall become the first deliverer, with a compliance obligation to CARB for the GHG allowance costs associated with that particular contract until either (a) the contract term expires; or, (b) the contract is renegotiated.
ii. The electric generator is relieved of its GHG compliance obligation associated with the emissions from that contract, until (a) the contract term expires; or, (b) the contract is renegotiated between counterparties. (IEPA2)

Response: We realize that a portion of generators and industrial steam producers have reported that some existing contracts do not include provisions that would allow full pass-through of carbon costs associated with the cap-and-trade program. We closely examined this issue, but do not believe it is the role of the regulator to negotiate contracts for parties engaged in an agreement, nor will we treat entities differently who do have negotiated contracts. In several cases, we are aware and encouraged by knowledge of parties that are in the process of, or already have, negotiated new contracts to resolve this issue. We believe that bilateral contract negotiations provide the best resolution to this issue.

As a result, in Resolution 11-32 the Board directed the Executive Officer to monitor progress on bilateral negotiations between counterparties with existing contracts that do not have a mechanism for recovery of carbon costs associated with cap-and-trade for industries receiving free allowances pursuant to Section 95891, and to identify and propose a possible solution, if necessary. For fixed-price contracts between independent generators and investor-owned utilities, the Board further directed the Executive Officer to work with the California Public Utilities Commission to encourage resolution between contract counterparties.

Additionally, we agree that there should be equal treatment for both those that purchase electricity from the grid and those that purchase electricity from a local generator. We are seeking equal treatment for those end users that bear the cost of the cap-and-trade program from indirect sources.

Currently, the CPUC proceeding is addressing utility costs and revenue issues associated with greenhouse gas emissions. Once the CPUC proceeding has concluded, and we have determined to what degree facilities face the indirect carbon costs from purchased power that we expect will be embedded in utility rates, we will revisit this issue and seek a more equitable solution.

CHP Heat Rate

I-121. Comment: Appendix B explains that "[i]n the development of the product benchmarks, adjustment factors were used to account for the carbon costs embedded in energy flows as shown in Table A." Presumably, these factors were used to assign CHP emissions to thermal and electric energy products to adjust emissions in or out of the numerator of a facility's emissions intensity. For example, if a facility that has an onsite CHP plant exports power to a utility or third party, the facility's MRR would be adjusted to remove emissions associated with those exports. While CARB may have chosen appropriate values to use for each product, it is not clear how the values were used. One approach is to use a residual method. For example, thermal emissions from a facility could be determined residually by taking the CHP facility's total emissions and subtracting electricity emissions, calculated using the power adjustment factor (0.421 MT/MWh). Alternatively, electricity emissions could be determined residually by taking the facility's total emissions and subtracting thermal emissions, calculated using the heat factor (0.0663 MT/MMBtu). The second approach is to use the two adopted factors together to create a proportional assignment of emissions in a manner similar to the California Climate Action Registry (CCAR) methodology. Under this methodology, electricity emissions are determined as follows:

ETO – (((OTH/.8)/(OTH/.8+ (OE/.42)) * ETO)
Where:

ETO = CHP Facility's Total Emissions
OTH = CHP Thermal Output in MMBtu
OE = CHP Electrical Output in MMBtu

EPUC recommends that CARB employ its adopted factors using the CCAR methodology, which offers the most moderate results among the options. There may be an inclination as a result of the CHP Settlement to use the power adjustment factor (8125 Btu/kWh or 0.431 MT/MWh) in a thermal residual calculation. CARB should avoid this result for three reasons. First, the heat rate employed in the CHP Settlement of 8125 Btu/kWh was intended to reflect an "avoided" heat rate, not an actual CHP heat rate. Second, the 8125 Btu/kWh factor is relevant under the CHP settlement only through mid-2014. Using a factor that is relevant for only 18 months of an 8 year program does not seem balanced. Third, the electric residual method using 8125 Btu/kWh can result in distorted thermal efficiencies. For example, assuming a CHP with a simple cycle heat rate of 11,600 Btu/kWh and a 1.5 heat to power ratio, the residual electric method at 8125 Btu/kWh would allocate only 30 percent of the total emissions to steam. This compares with a thermal allocation of 49 percent under the 80 percent boiler residual method, 41 percent under the traditional CCAR method (using 42 percent efficiency) and 60 percent under the CPUC's output method. For these reasons, EPUC recommends employing the adopted heat and power adjustment factors in the CCAR methodology for purposes of splitting thermal and electric emissions from a CHP facility. (CAC, EPUC2)

> **Response:** We believe allocation to the industrial sector should be designed to create a smooth transition into the program in the near term and to avoid leakage in the long term. Therefore, allocation should be based on expected carbon costs in energy prices rather than any division of emissions for each individual CHP facility between co-produced heat and power. Following this logic, we employ a factor for heat purchased or sold and a factor for power sold selected to represent the carbon costs that will be incorporated into the markets for heat and power. The carbon price embedded in the price of electricity is assumed to be set by a marginal generator with a heat rate of 8,125 Btu/kWh which equates to an emissions factor of 0.431 ton CO_2e/MWh. For the market for heat the reference is assumed to be a natural gas fired boiler which produces steam with an emissions rate of 0.06244 ton CO_2e/MMBtu of steam.

Compliance Obligation of Sales and Inequity of Grid and Direct Access

I-122. Comment: Treatment of Cogeneration and Electricity in Benchmarks - The GHG emissions that are incorporated into the benchmarks for oil and gas and refining and for all sectors should include the emissions for the net power and heat consumed and sold. Some of the power from these facilities is consumed onsite and some is exported. Only the power consumed onsite should be charged against the facility emissions in the benchmark calculation. Furthermore, in order to ensure that there is even treatment of operators with cogeneration facilities compared to net purchasers of electricity and heat, indirect emissions from imported power from the grid and heat from other facilities should also be included in the benchmark calculation. Otherwise, ARB would be creating an incentive for companies to favor purchasing power from the grid and/or outsourcing thermal purchases because it does not count against their benchmark performance. To address these changes in the oil and gas production benchmark, a calculation supporting this approach was provided to ARB as part of the WSPA oil and gas thermal and non-thermal benchmark proposal. To address these concerns in the WSPA refinery benchmark proposal the only change would be to subtract the emissions from the sale of power because the EII takes electricity and cogeneration into account in the calculation of the EII. Under the proposed regulation, it would be appropriate for oil and gas producers to receive, at a minimum, the allowances for indirect electricity use directly (as opposed to the provision of those allowances to the distributors). To address concerns that double counting could occur, ARB could deduct these allowances for imported electricity from the utility sector. (CHEVRON3)

> **Response:** We agree that there should be equal treatment for both those that purchase electricity from the grid and those that purchase electricity from a local generator. We are seeking equal treatment for those end users that bear the cost of the cap-and-trade program from indirect sources.
>
> Currently, the CPUC proceeding is addressing utility costs and revenue issues associated with greenhouse gas emissions. Once the CPUC proceeding has concluded and we have determined to what degree facilities face the indirect carbon costs from purchased power that we expect will be embedded in utility rates, we will revisit this.
>
> Similar to other generation facilities, we recognize that CHP facilities hold a compliance obligation for emissions associated with electricity generation that is exported. We expect that this sale of electricity will allow efficient generators to recover their carbon costs for these sales.

Energy-Intensive Trade-Exposed Industries Benchmarks' Effect on CHP

I-123. (multiple comments)
Comment: Appendix B to the July 25, 2011, Revised Regulation proposes to exclude from the product benchmark calculation indirect emissions associated with "power purchased." The proposal appears to be based on the concern that reflecting indirect emissions would compensate an EITE facility for these emissions through the benchmark. Consequently, if grid power users receive benchmark compensation and utility compensation for indirect emissions, they could receive double recovery for the same emissions costs. CARB's concerns are misplaced. While complications arise from separate treatment of direct and indirect emissions in allowance allocation, these issues do not need to be solved in the benchmark calculation. The primary goal should be first to get an accurate benchmark that reflects all emissions arising from the facility's

production. If necessary, depending on the outcome of the CPUC's allocation process, adjustments can then be made to the benchmark award to prevent double recovery. Moreover, the exclusion of indirect grid power emissions from the benchmark calculation would turn the State's goal of supporting CHP operation and development on its head, incentivizing purchased power over the continued operation and development of CHP. For these reasons, EPUC recommends that all emissions, whether direct or indirect, be included in the calculation of a product benchmark. Once the benchmark is established, CARB can then address the potential for duplicative compensation through the adjustment of benchmark allocations. The aim of the product benchmark should be to determine the emissions intensity of producing a unit of output. The true emissions intensity is a function of both direct, on-site emissions and indirect emissions for energy consumed in production. Exclusion of indirect emissions thus leads to a distortion of a facility's and a sector's emissions intensity. CARB has expressed clear support for the continued operation of existing and development of new CHP generation. The Scoping Plan estimates that reliance on CHP can generate 6.7 $MMTCO_2e$ in emissions reductions. Resolution 10-42 calls for appropriate incentives to increase reliance on CHP. If indirect emissions are excluded from product benchmark calculations, the effect will be to depress the benchmark to a level that fails to reflect the full scope of electricity GHG emissions resulting from a unit of output. Depressing the benchmark in this way will affect grid purchasers and self-generators differently. A grid power purchaser under this scenario could receive full compensation for its electricity emissions even with a depressed benchmark because its benchmark award will be separately supplemented with a utility allowance value allocation. A CHP self-generator, in contrast, can look only to its benchmark award to cover its emissions costs. If the benchmark is artificially depressed by the exclusion of certain electricity emissions, a CHP self-generator is highly unlikely to receive sufficient coverage of its electricity-related emissions. The natural effect will be to drive self-generators and their steam hosts toward a combination of boilers and grid power and away from CHP. Not only will this limit efficiency and reliability, it will put additional strain on the electricity supply and transmission system. For this reason, the product benchmark proposal runs contrary to the Scoping Plan and Resolution 10-42, which seek to encourage retention of existing and addition of new CHP facilities. A variety of solutions could be applied to the problem created for CHP by excluding indirect electricity emissions from the product benchmark. Only one solution, however, would achieve all of CARB's goals: including indirect GHG emissions in the product benchmark calculation. Indirect emissions from grid electricity purchases would be incorporated into the benchmark at the rate of 0.431 MT for each MWh of grid electricity consumed by a customer during the baseline period, ensuring that both imports and exports are accounted for using the same proxy. Under this approach, the benchmark would most accurately reflect the sector's GHG emissions intensity. The benchmark could then be used to determine allowance allocations to all facilities, regardless of their electricity supply sources. The direct/indirect distinction would arise through an adjustment of the allowance award to reflect compensation received by a facility directly from the electric utility for indirect emissions. CARB may be tempted to assume that a correct "price signal" for grid power would also solve this problem. This approach, however, would leave EITE grid power users burdened with the full cost of indirect GHG emissions and would run contrary to

CARB's objectives of avoiding leakage. By definition, EITE entities cannot recoup GHG costs from their product markets due to the significant potential for leakage. Declining to allocate the allowance value out of the desire to ensure a price signal could also run contrary to the goal of mitigating the AB 32 rate impact on utility customers. Finally, it would do nothing to correct the accuracy of the benchmark as a measure of emissions intensity. For these reasons, CARB should make clear that all electricity-related emissions will be included in calculating a product benchmark. (CAC, EPUC2)

Comment: CARB's revised Regulations fail to include indirect emissions associated with the use of electricity used in a manufacturing operation from the calculation of the Product Benchmark. (See Appendix B to the July 25, 2011 revised Regulations.) In addition to CLECA's concerns that such failure will risk causing EITE customers not to have full coverage of their new Cap and Trade costs, this approach unnecessarily and improperly sends a very discouraging signal to customers who might be interested in new CHP in California. CARB's logic is that indirect costs associated with electricity use will somehow be compensated by the utilities using their allowance auction proceeds. As we have discussed, CPUC may have different ideas about the disposition of such proceeds. But, even if the auction proceeds were used to provide rebates or bill reductions to customers in relation to their electric use, this approach fails to acknowledge that some customers currently self-provide or would like to self-provide all or a portion of their electrical requirements through CHP or other renewable technologies. Consider a situation in which an industrial customer, whether EITE or not, is currently a full bundled utility customer but would like to install CHP or a renewable technology to meet 50 percent of its electric requirements two years hence. Assuming that the allowance auction proceeds are actually used to provide bill reductions to the customer based on its utility electric purchases, a decision to install CHP or a renewable technology to meet 50 percent of its requirements would mean a loss of 50 percent of the auction proceeds. This will create a powerful disincentive to the installation of new CHP or renewable power and it will run directly counter to the CARB's own endorsement of the goal of achieving nearly 7 million tons of GHG reductions through the increased use of CHP. While the CARB, in Resolution 10-42, calls for incentives to encourage CHP, its regulations will act to discourage CHP. This can be readily solved by the CARB including indirect emissions in the product output benchmark for each industry. CLECA strongly urges the CARB to make this change. (CLECA)

Comment: The current regulatory scheme will discourage new CHP, not only by excluding indirect emissions in benchmarking, but by failing to address the treatment of allowances when a facility shifts from grid power to self-generation. Assuming the CPUC implements the AB 32 goal of minimizing leakage, an EITE entity purchasing grid power will receive allowance value directly from its distribution utility to offset the GHG compliance costs embedded in electricity rates. If the EITE then decides to invest in additional CHP capacity, it will be responsible for increased direct GHG compliance costs and will lose its share of allowance value from the utility. Not only could it lose the existing allowance value from the utility, it would likely not receive an increase in allowances through benchmarking, since the benchmark award once set will vary only with product output. As a result, the EITE entity's share of allocated allowance value will decrease even though it will face increased direct emission compliance costs. This is antithetical to encouraging new CHP development. To avoid this CHP disincentive, CARB should require electric utilities to continue providing EITE ratepayers a share of allowance value once they leave utility service. This approach makes sense in light of CARB's approach to allocation of allowances to utilities. If the customer's load was a part of the 2008 usage CARB employed to calculate the 97.7 MMT electric utility allocation, it should take a proportional share of that allocation with it as it leaves the utility system. Two other approaches could be used. First, designing a product benchmark that both includes indirect emissions and adjusts for direct compensation of grid users by their utility could mitigate some of the impact. Second, a methodology that provides a CHP adder to the applicable industrial benchmark could provide mitigation. However, without a shift of allowances from the utility sector to the relevant EITE industrial sector, these approaches would result in short-changing the CHP developer and provide an undue windfall to the electricity sector. Modify section 95892(d)(3) as follows:

> <u>(3) Investor owned utilities shall continue to provide an energy-intensive, trade-exposed customer a share of auction proceeds to offset the greenhouse gas compliance costs based on historic usage if the customer leaves the system to be served by combined heat and power.</u> (CAC, EPUC2)
>
> **Response:** We believe that an appropriate carbon price needs to be embedded in all power prices to create the right incentives to encourage CHP at EITE industries. In establishing the appropriate carbon price in rates, the CPUC and the governing boards of POUs may need to account for other greenhouse gas-reducing policies, including the 33 percent renewable portfolio standard and the impact of these programs on electric rates. To the degree that EITEs face unrecoverable indirect carbon costs from purchased power, we could potentially amend the product benchmarks to incorporate additional compensation, if needed to help minimize leakage. This approach might require the electrical distribution utility allowance allocations to be reduced commensurately to maintain the level of the overall cap, as well as to prevent double-compensation for EITE indirect emissions costs and/or ratepayer windfalls. We continue to work with the CPUC, CEC, and publicly owned utilities to address these issues and ensure that proper carbon pricing occurs. We will revisit this issue once the CPUC's proceeding addressing utility costs and revenue issues (R.11-03-012) associated with greenhouse gas emissions concludes.

Definition

I-124. Comment: The revised Regulation modifies the definition of "cogeneration." The revision creates an ambiguity in the definition and fails to ensure alignment with the current California regulatory framework that defines and governs cogeneration.

The revised Regulation defines cogeneration in a manner that requires "onsite generation." The use of the term "onsite," which is not defined in the Regulation, creates an ambiguity. The ambiguity arises from the fact that some facilities use cogeneration thermal or electric energy that is not produced on their site, but delivered "over the fence", on the site of another entity. Public Utilities Code (PUC) section 218 permits "over-the-fence" transactions when electricity is delivered by the generator for: (1) Its own use or the use of its tenants, and (2) The use of or sale to not more than two other corporations or persons solely for use on the real property on which the electricity is generated or on real property immediately adjacent thereto. The use of the term "onsite" in the current cogeneration definition could be interpreted to exclude these over-the-fence transactions that are currently permitted. We request ARB eliminate any ambiguity that could adversely impact the current regulatory framework governing cogeneration. Modify section 95802(a)(47) as follows:

(47) "Cogeneration" means an integrated system that produces electric energy and useful thermal energy for industrial, commercial, or heating and cooling purposes, through the sequential or simultaneous use of the original fuel energy. Cogeneration must involve onsite <u>the </u>generation of electricity and useful thermal energy and some form of waste heat recovery. (EPUC2, CAC)

> **Response**: Electricity and thermal energy produced by "over the fence" cogeneration units that are outside of the facility boundary must be reported by the thermal host or electricity end-user facility as "electricity purchased or acquired." As long as the cogeneration facility and the thermal host/electricity end-user facility draw their facility boundaries correctly, there is no ambiguity. Although we do not think the word "onsite" has the effects that the stakeholder is concerned about, the removal of the word "onsite" from this definition does not have any effects on rule applicability and source categorization. The clarification was made so that an operator of a facility that purchases heat or steam from a separate "over-the-fence" facility is not required to indicate that he has a cogeneration unit at his facility. The operator of the "over-the-fence" unit would report as a separate cogeneration facility.

Miscellaneous

I-125 Comment: Treatment of cogeneration in the Cap and Trade regulation penalizes SMUD ratepayers for operating electrical generation facilities as co-generators of electricity for supply to SMUD's electrical grid while also supplying steam to nearby industrial facilities. The specifics of such arrangements at three of SMUD's major electrical generation facilities clearly have energy, environmental and community use benefits, and there are GHG savings for combined production of electricity and steam relative to their otherwise separate production. However, there is nonetheless a marginal additional natural gas use requirement at those facilities needed to supply steam for industrial use. Information to be provided under Mandatory Reporting Regulation (MRR) section 95112 allows for separating the GHG emissions associated with generation of electricity from those associated with supply of industrial heat.

However, separate reporting of the two functional emissions is no longer required as part of the MRR and the cap and trade program 15-day language imposes on SMUD and our ratepayers an obligation to provide allowances for all the emissions emitted from the power plant stack, including those calculated as belonging to supply of the industrial heat. None of the facilities that SMUD sells steam to will be a Covered Entity under the Cap and Trade Regulation, and existing steam sales contracts do not allow for charges for reimbursement to SMUD for allowances obligated by the emissions fairly attributable to the industrial faculties. Without regulatory relief, SMUD's ratepayers will be forced to bear a significant cost burden and three otherwise environmentally beneficial energy arrangements will be forced to carry an unintended economic burden imposed by regulation; an economic burden that penalizes more efficient use of energy and cleaner overall resources in our community. Unfortunately unless SMUD ratepayers obtain relief either through an increased allocation of allowances or a reduction in the cogenerator allowance obligation, the combined 330MW of existing cogeneration will have another economic reason to revert to production of electricity only. SMUD recommends the ARB allocate a small portion of the industrial allowances to cover emissions associated with provision of steam to these industrial customers. While these arrangements are not common in California, they are no less beneficial than arrangements in which the industrial source owns the generating source and exports electricity to the wholesale market. Given their value is the same, their treatment should be equivalent, so as not to discourage continuation of the arrangements with these facilities or prevent similar future arrangements from being plausible. Considering the efficiency benefits from being able to develop cogeneration using combined cycle technology, ARB should certainly be encouraging this type of arrangement if it wishes to achieve its goals for efficient cogeneration in California. Modify section 95852 as follows:

> (8) An operator of a facility covered under sections 95811(b) and 95812(c)(2) that is a cogeneration facility in normal operation prior to 2011 and which sells process heat, under contracts entered prior to 2011, to facilities that are not covered entities shall have a compliance obligation (CO2e $_{\text{covered}}$) that reduces the total reported facility emissions by an amount attributable to combustion emissions for production of the process heat. Partition of GHG emissions attributable to electricity and process heat production shall be calculated using the efficiency method and verified information reported under MRR section 95112. (SMUD3)

> **Response:** We believe the allocation to SMUD as an electrical distribution utility is already sufficient to cover ratepayer costs associated with the issues raised in the comment. We desire all sellers of heat to attempt to recover carbon costs in the price of the steam sold. This will create an incentive for conservation of steam energy. Facilities with direct emissions less than 25,000 metric tons CO_2e/year, but that face carbon costs from purchase steam, may opt-in to the cap-and-trade program to become eligible for free allocation to help reduce these costs and minimize leakage risk.

I-126. Comment: ARB has proposed a complicated scheme of providing free allowances to utilities to offset increased costs they will bear from electricity generation facilities like cogeneration plants. Unfortunately, this puts a significant and unnecessary administrative burden on electricity generation facilities like cogeneration, who now must determine the allowances they will need, track and participate in auctions, determine what costs can be past on the utility, and assess if this mechanism provided adequate reimbursement for them to keep their operation going. These represent real administrative actions and costs these facilities must bear. Today, nobody performs these actions at these facilities, adding a new layer costs to an industry with low margins. We propose that ARB provide allowances directly to the electricity generating facilities like cogeneration. By doing so, these facilities will know what allowances they will receive; costs will be minimized by removing the entity in the middle (utility) without changing the number of allowances distributed; and facilities will have greater clarity of their needs and costs under the proposed cap and trade regulation. Helping us minimize the costs of this regulation will allow us to continue providing efficient electrical generation to the State of California. This is something that we hope the ARB can seriously consider and engage in further discussion with groups like the California Cogeneration Council and the utilities. (GPI3)

> **Response:** We acknowledge that compliance with the regulation will have administrative costs (acquiring allowances and offsets, reporting requirements, and recordkeeping) in addition to direct compliance costs. Allowances are provided to utilities to compensate ratepayers for the compliance cost burden of the program, and to industrial producers to minimize leakage. We did not modify the regulation to include direct allocation to cogeneration to recover administrative overhead associated with cap-and-trade program compliance.

I-127. Comment: CARB should consider CHP impact from assistance factors reductions in the second compliance period. In the second compliance period, when assistance factors are dropped for some sectors and direct emissions coverage is reduced, CHP GHG emissions for serving on-site load will not be fully covered. If grid power purchases continue to receive coverage, incentives again will be strongly tilted toward grid power. It will be important for CARB to address the issue of CHP disincentives in advance of the second compliance period to prevent impairment of the Scoping Plan's goal of maintaining and expanding the state's CHP fleet. (EPUC2)

> **Response:** We disagree that the assistance factor will create issues for incentives for self-generation vs. grid purchases of power. The commenter is making an assumption about the type of compensation that will be given in electric rates. Currently, a CPUC proceeding is addressing utility costs and revenue issues associated with greenhouse gas emissions. Once the CPUC proceeding has concluded and we have determined to what degree facilities face the indirect carbon costs from utility rates, we will revisit this issue.

Long-Term Contracts

General

I-128. Comment: ARB's proposed definition of "Long-Term Contract" as one entered into before January 1, 2006 with a term of "five years or more" raises a number of serious issues. Under the current Long-Term Procurement Plan approved by the CPUC, SCE is only permitted to procure products for a term of up to five years (excluding renewables and/or combined heat and power (CHP) contracts). This definition would exclude most if not all of SCE's existing and future power agreements with generators that would require allowances in the Cap and Trade program from participating in any beneficial holding relationships. ARB should modify the definition to procure products for a term of one year or more. This period is consistent with that used in SCE's solicitations, but will exclude short-term and spot contracts for the delivery of electricity.
Modify section 95802(a)(150) as follows:

> "Long-Term Contract" means a contract for delivery of electricity entered into before January 1, 2006 for the term of ~~five years or more~~ one year or more. (SCE3)
>
> **Response:** We understand that the CPUC disallows longer-term contracts for SCE. According to the commenter, these contracts will expire January 1, 2011. Therefore, we did not modify section 95802(a)(150) with the proposed changes.

I-129. Comment: For a small subset of IPPs operating under existing, long-term contracts, currently no viable mechanisms exist within their contract structures to recover the cost of the GHG allowances they are obligated to obtain under the C&T program. IEP recommends that the definition for "Long-Term Contract" should be amended to reflect the date AB 32 was chaptered: September 27, 2006. Modify section 95802(a)(150) as follows:

> "Long-Term Contract" means a contract for the delivery of electricity or thermal energy entered into before January 1, September 27, 2006 for the term of five years or more. (IEPA2)
>
> **Response:** The definition for long-term contract was included to address beneficial holding relationships in section 95834. We are not proposing to use this date for any other purpose. We did not modify section 95802(a)(150) with the proposed changes.

I-130. (multiple comments)
Comment: ARB should clarify its definition of a “long-term contract” and its relationship to the beneficial holding section. It is unclear from the draft language whether an electrical distribution utility can only enter into a beneficial holding relationship when SCE has entered into a long-term contract with that entity. SCE requests that ARB clarify that language, which states that an agent in a beneficial holding relationship “may not also serve as the agent” in another without a long-term contract. This can be read to say that an agent may enter into one beneficial holding relationship without a long-term contract, but cannot enter into more than one such relationship. (SCE3)

Comment: There is a second relatively minor issue that Wellhead understands is already understood by CARB. That is the "beneficial holding relationship" provisions should be available to all long term contracts, not just those executed at an earlier time. This is a useful mechanism and there are recently negotiated/executed contracts that would benefit from its administrative simplicity. The change to the Regulations to fix this issue is to simply remove the date limitation in the definition of Long-Term Contract. (WEC2)

Comment: Long-term contracts are not restricted to just to those that existed prior to January 1, 2006. This should be deleted from the definition for clarity. If there is reason to limit the provision for Beneficial Holdings to long-term contracts in place prior to a specific date, then that date should be included in the section of the Regulation where it is applied. In this case, section 95834(2)(A) makes reference to “long-term contracts” as it relates to an electrical distribution utility's beneficial holding relationship with a provider of electricity. Modify section 95802(a)(150) as follows:

> (150) “Long-Term Contract" means a contract for the delivery of electricity entered into ~~before January 1, 2006~~ for the term of five years or more. (LADWP4)
>
> **Response:** The language referencing long-term contracts in section 95834 was removed because the language unintentionally allowed only the utility to declare the existence of the beneficial holding relationship. The modified language requires confirmation by both the principal and agent before the beneficial holding relationship can exist. The definition for “long-term contract” was included to address beneficial holding relationships in section 95834. We are not proposing to use the date included in the regulation for any other purpose.

Long-Term Contracts (Non-CHP)

I-131. (multiple comments)
Comment: Nothing in our long-term power purchase agreement (PPA) provides for the pass through of costs associated with the Cap and Trade Program. Therefore, Goal Line is exposed to unrecoverable costs under the currently proposed regulatory language in the Cap and Trade program. The PPA, which remains in effect through February of 2025 spans all three compliance periods and has specific provisions that

prevent Goal Line from selling any of its electrical output to any entity other than SDG&E. We believe it is likely that Goal Line will need relief on a case-by-case basis from ARB. (GOALLINE)

Comment: The 15-Day modifications fail to address the problem faced by generators with long-term contracts that do not allow for recovery of GHG allowance costs. Staff believes that bilateral contract negotiations would provide the best resolution of this issue. Should contract renegotiation not be possible in all cases, staff will continue discussions with counterparties to consider how this issue should be resolved in the regulation. Calpine is encouraged by staff's intention to continue evaluating how this issue should be resolved in the final Regulation. Calpine is also encouraged by the inclusion of a definition of "long-term contract" in the 15-Day Modifications, which addresses contracts for the sales of steam (section 95802(a)(150). This could provide a starting-point for resolving this issue in the final Regulation. However, Calpine disagrees with the staff's suggestion that this problem can be resolved through bilateral negotiations in all cases. Pursuant to the Board's instructions in Resolution 10-42, staff cannot rely upon the speculative assumption that all contracts will be renegotiated, but must publish proposed 15-day changes that address this issue at the earliest opportunity. Calpine believes that the best way to address this problem is through a direct allocation of emissions allowances to generators subject to long-term contracts that provide no mechanism for recovery of allowance costs. This would provide transitional assistance until such time as the existing contract expires or is substantively amended, as reflected by the specific language we proposed in our December 2010 comments. However, we are open to working with CARB staff on other solutions, such as attestation requirements that would preclude covered entities or opt-in covered entities from receiving any free allocation for industry assistance per section 95891, unless the entity affirms that it does not purchase power or steam from another covered entity (other than an electrical distribution utility) and, where it does, both the industrial facility and its provider of electricity and steam certify that they have appropriately allocated responsibility for any costs attributable to GHGs between themselves. (CALPINE3)

Comment: The proposed Regulation is silent on the treatment of existing, long-term contracts that have no reasonable means of recovery of GHG allowance costs. As a result, all Independent Power Producers (IPP) are required to purchase 100 percent of their allowances or offsets, and presumably recover these costs from their power purchase and sale agreements. The universe of IPPs includes a relatively small but important number of IPPs who entered into power purchase and sale agreements prior to enactment of AB 32, and thus could not contemplate the recovery of these unknown future costs. These facilities are facing new, variable operating costs of compliance for which they have no reasonable means of recovery. In contrast, the utilities and industrial entities that are required to participate in Cap and Trade are provided with the vast bulk of their allowances at no cost even when they have a reasonable means of market-based and/or rate-based recovery. Furthermore, in those circumstances when a Utility Owned Generator (UOG) enters into an auction to purchase allowances to meet its compliance obligation, the expenditures it makes as an electric generator revert back on a dollar-for-dollar basis to the same utility in its function as a load-serving entity. The result is that a utility and the utilities' retail customers are indifferent to the costs associated with an UOG's operations. Unfortunately, this is not the case for the IPPs that will be competing with the UOG, as they cannot rate-base their allowance or offset purchases in such circumstances and cannot recover their costs from the market place. We recommend that all electric generators be given a comparable means of cost recovery of their compliance obligation. The Regulations should allow IPPs to make use of an expanded Beneficiary Holding Account or the Cap and Trade program should allocate allowances directly to this limited set of IPPs in a non-discriminatory manner, comparable to the treatment afforded utility-owned generation plants. (WM3)

Comment: Wellhead remains very concerned that the proposed cap-and-trade regulations are unfair to, and create problems for, power sales contracts entered into before AB 32 was signed into law when such contracts do not have any mechanism available for recovery of GHG costs (hereinafter "Pre-AB 32 Contracts"). The failure to address this matter creates multiple problems, and not just for the generator. Foremost, without addressing this issue, the allocation of allowances to utilities is fundamentally flawed because it gives allowances based on costs that will not be incurred by the utility. Second, not only will the generator be without any ability to recover its costs, but behaviors in contradiction of the state's GHG emission reduction goals are rewarded because the buyer will be economically benefit by running the facility more because it does not incur the GHG costs. Hence, CARB's policy intentions for GHG costs to be directly considered in the economic dispatch of generating resources and for ratepayers to see the carbon price signal of generation purchased by a utility will be undermined. It is therefore disappointing that the proposed regulations do not address the issue, based apparently on the hope by CARB, as indicated in the staff summary, that Pre-AB 32 Contracts will be renegotiated.

While bilateral negotiations could possibly solve the problems in some instances, relying on renegotiation does not make good public policy as a primary strategy, particularly without clear guidance and a backstop alternative, as we propose below. Under the proposed regulation, Pre-AB 32 Contracts will be the only fossil fueled power purchase options for which the distribution utility does not incur carbon costs, and in the case of tolling agreements where a utility can call on or effectively run the generator without incurring such cost the utility will have an incentive not to renegotiate the Pre-AB 32 Contract. Moreover, the result of this built-in utility incentive to run such a generator more than would be the case if it did confront appropriate carbon costs will be increased GHG production, is contrary to AB 32's primary policy objective. Thus, relying on parties to renegotiate contracts is unlikely to resolve the Pre-AB 32 Contract concern in addition to being cumbersome and expensive from a transactional perspective. Even if CARB had authority to mandate renegotiation, which we doubt, such an approach would still require CARB to revisit its decision allocating allowances to the electric utilities and/or use allowances allocated to its set-aside at some future date if renegotiations are unsuccessful. CARB should act decisively to avoid the uncertainty, controversy and delay that will result by failing to address the issue at the outset. Most importantly, not addressing the issue is clearly inconsistent with the allocation of free allowances to distribution utilities. In the allocation methodology, CARB explicitly notes that there will be a cost burden resulting from GHG compliance costs associated with fossil generation being passed from suppliers (whether purchased under contract or produced from utility owned generation) to utility customers. Allowances CARB provides to a distribution utility are intended to result in full compensation for GHG compliance costs that are expected to be passed through to consumers. The determination of how many free allowances a utility receives assumes all of its fossil based generation has a GHG cost. Pre-AB 32 Contracts were included in the utilities' S-2 Filings, which are the basis for estimating the utilities' costs associated with the Cap and Trade program. However, Pre-AB 32 Contracts will be a source of fossil fueled power for which the utility does not incur GHG compliance costs under the proposed regulations. Hence, unless the regulations require the utility to provide Pre-AB 32 Contract suppliers with allowances associated with the power they take under the Pre-AB 32 Contracts (which would be the most logical, best and simplest solution), the Regulations will freely allocate allowances to distribution utilities for GHG costs that will not be incurred by them. (WEC2)

Comment: Forward term contracts at fixed prices should receive free allowances. Section 95811 requires generators and importers of electricity into California to account for the CO_2 emissions associated with their power production and imports. Shell understands the need to include emissions from the power sector under the Cap and Trade program. However, for generators located within, or connected to the California Grid that entered forward term contracts at fixed prices, this requirement will create an economic loss that was not accounted for at the time the transaction was executed. To address these losses, staff has included a recommendation in the “Notice of Public Availability of Modified Text and Availability of Additional Documents" that bilateral contract negotiations would provide the best resolution. Shell respectfully disagrees and requests that CARB reconsider this recommendation. The number of free allowances associated with the outstanding contracts that could and should be distributed to the contract holders is minimal. However, the economic impacts are significant. Directing bilateral parties to renegotiate when there is no incentive for the advantaged party to so do virtually guarantees the disadvantaged party will be penalized. Shell urges ARB to provide free allowances to those entities that entered fixed price long-term contracts and have no ability to recover the cost of carbon. (SHELLOIL)

Comment: The issue of stranded cost recovery has come up repeatedly throughout the development of the regulation. The inability of a facility to recover an added cost due to a pre-existing contract presents some unfair market conditions for certain electricity generating facilities. NextEra supports the comments submitted by IEP and WPTF on this topic. Although the obvious fix to this issue lays in the renegotiation of contracts and power purchase agreements, this may not be an option for some parties involved. In order to address this issue fairly, ARB must incent both parties to renegotiate the contracts. NextEra urges ARB staff provide some assurance that this issue will be addressed in this rule. (NEXTERAENERGY2)

Comment: Panoche, like a number of other California independent power producers with long-term power purchase agreements—long-term contract generators (LTCG)—entered into power purchase agreements with utilities before AB 32 was enacted or the regulation of GHGs was under consideration by the State of California. Under many of these contracts, the power generation rates and price structures are specified and fixed. Additionally, the contract terms do not allow for price modifications arising from changes in environmental regulatory policy. Accordingly, unlike with other sources, such as merchant generators or traditional public utilities, Panoche cannot reduce contractually required output nor pass through new environmental compliance costs resulting from the implementation of AB 32. We understand, as expressed in the Initial Notice of Availability, the July 15 stakeholder meeting, and the Notice of Public Availability of Modified Text, that CARB staff would prefer that LTCGs and their customers work together to resolve this issue. Knowing of this preference, we have reached out to PG&E in an effort to address the matter. Unfortunately, we have not been able to obtain a satisfactory resolution. Without relief, the new costs associated with AB 32 compliance will have a substantial negative impact on the financial viability of our facility as well as a limited number of other LTCGs. These facilities should not be penalized for contracts entered into at a time when the regulation of GHGs was not contemplated. Rather, we urge the Board to provide a suitable framework for resolving this issue so as avoid impairing the financial viability of pre-existing contracts. We would suggest the Board consider granting allowances to LTCGs with pre-AB 32 power purchase agreements under limited circumstances, including allowances being granted only during the remaining term of a pre-AB 32 contract. In addition, the Board could require in the regulation that it be demonstrated to the satisfaction of the CARB Executive Officer that a LTCG cannot reasonably expect to recover the costs of allowances needed to meet its cap-and-trade compliance obligations under its pre-AB 32 contract. To encourage negotiations between affected LTCGs and utilities, the Board should also consider providing that the parties engage in good-faith, bilateral negotiations to resolve the issue of cost of compliance during 2012, before compliance obligations commence on January 1, 2013. If the parties have not come to a mutually-agreeable resolution at that time, the regulation should provide that LTCGs are granted allowances under the outlined terms. Precedence for this type of solution can be found under the Clean Air Act, particularly in the Acid Rain Program and in some of the RGGI program states. (PEC)

Comment: An allowance set-aside should be added to section 95870 to provide for direct allocation of allowances to independent generators with the inability to renegotiate long-term contracts without provisions for carbon pass through. (WPTF2)

Comment: ARB should consider, on a case-by-case basis, the need for adjustment to allowance allocations to firms operating under long-term contracts. ARB previously recognized that there may be a need to accommodate parties in the electric power generation industry subject to long-term contracts, noting in Appendix J to the proposed Cap and Trade Rule that it would further “evaluate…whether some specific contracts may require special treatment” [App. J, p. J-16, note 15 (Oct. 28, 2010 draft)]. ARB should provide similar case-by-case adjustments for hydrogen producers. Both the

Waxman-Markey and Kerry-Boxer federal bills allocated allowances to parties who would be unable to pass on compliance costs under long-term supply contracts. ARB should protect parties to long-term contracts by extending the 100 percent allocation provided for the first compliance period until the end of the contract term. (IGPACC)

Comment: Our predominant concern focuses on the lack of assistance for generators with long-term contracts that do not provide for full pass-through of carbon costs. CARB staff has suggested that bilateral contract negotiations would be the preferred method to handle this issue. However, for contracts with a non-IOU as the purchaser of power for the contract there is no pressure on the purchaser to renegotiate, particularly if the purchaser has an advantage over the market pricing. Therefore, we believe that CARB needs to directly address in the regulation how to assist the independent power producers that cannot pass through carbon costs in existing contracts. Other sectors, including utilities and industrial entities, are provided a direct allocation of allowances. Independent power producers should have at least equal treatment. Other solutions that redirect the obligation for carbon cost to the purchaser of power in these contracts could also accomplish the goal. Regardless of the final methodology, it is essential that CARB address the existence of these contracts and the financial burden they place on the power producers involved in them. Without equal treatment for the independent power producers, it would appear as if the implementation of AB 32 discriminates against a limited subset of generators. (BANKS)

Comment: Section 95890 should be modified to include requirements for direct allocation of allowances to independent generators with the inability to renegotiate long-term contracts without provisions for pass-through of carbon costs. The allocation should be limited to emissions incurred under the terms of the contract, and should be moved directly to the generator’s compliance account. (WPTF2)

> **Response:** Contracts that were entered into between generators and purchasers of electricity and/or steam, or between first deliverers and generators, were entered into under various negotiations regarding, among other items, environmental costs, or costs for fuel. Negotiated agreements between the parties reflect risks taken and borne by each party. For this reason, we believe that it is not our position or responsibility to make all parties whole within the regulation for contracts that are based on a fixed price and do not include a cost pass-through provision. However, we do not want to set up a scenario where parties that will receive allowances through direct allocation could realize windfall profits. We encourage parties to continue to either renegotiate their contracts, and/or generators to continue to evaluate opportunities to reduce GHG emissions by using alternative fuel options, or changes in operations. In addition, we continue to work closely with the CPUC to address the contracts that are within their purview, either under the Long Term Planning or the GHG Cost Revenue proceedings. We continue to urge stakeholders with the types of contracts described in the comment by Panoche involving an investor-owned utility to become a party to the CPUC proceedings.

To this end, in Resolution 11-32 the Board directed the Executive Officer to monitor progress on bilateral negotiations between counterparties with existing contracts that do not have a mechanism for recovery of carbon costs associated with cap-and-trade for industries receiving free allowances pursuant to Section 95891, and to identify and propose a possible solution, if necessary. For fixed-price contracts between independent generators and investor-owned utilities, the Board further directed the Executive Officer to work with the CPUC to encourage resolution between contract counterparties.

I-132. Comment: CARB's proposed GHG regulations and policies conflict with previously implemented policies favoring plants like ACE and the Rio Bravo Plants. The new cap-and-trade regulations, being developed in furtherance of present-day environmental goals, should not be structured so as to undermine those existing contracts encouraged by prior state policy and environmental goals, because doing so will increase the already high level of uncertainty in the California energy markets and reduce incentives for new investment precisely at the time it is needed most. (ACERIO)

Response: The ACE and Rio Bravo plants, as the commenter indicates, are plants that are considered Qualified Facilities (QFs). These plants combust fuels that result in GHG emissions that exceed acceptable rates agreed upon through the CHP settlement. At one time, these plants were considered alternative fuels, and were constructed in response to energy policies applicable approximately twenty years ago. AB 32 implements a goal for a reduction in emissions by the year 2020. The settlement acts as an additional incentive for these plants to make modifications to meet future GHG emission-reduction goals.

I-133. Comment: Transitional assistance to cogeneration facilities for conversion to low carbon intensity fuel technologies is beneficial to the State's economy. CARB should develop a transitional mechanism for high-carbon solid fueled facilities so that they can undertake the substantial investments necessary to change fuel types. Such a mechanism is entirely consistent with programmatic goals of CARB's AB 32 implementation given that the state's overarching policy is to achieve overall carbon emissions reductions by 2020 with minimal economic dislocations. (ACERIO)

Response: We do not agree that the regulation should include a transitional mechanism for these high-emitting fuels. We worked closely with stakeholders to discuss potential resolutions to the situation where generators are using high-emitting fuels. There are opportunities for other programs to assist these generators with plant modifications. For example, some stakeholders have indicated they will switch to fuels that will result in electricity that is eligible for Renewable Energy Credits. This decision reduces their compliance obligation in the cap-and-trade program and provides for an additional funding source to support fuel-switching.

I-134. Comment: The current draft Regulations do not provide any resolution to those entities with existing power sales contracts that do not allow recovery of GHG costs.

CARB has stated that it would address this issue and suggested it would provide special treatment to facilities unable to contractually pass through these costs. Despite these reassurances, the current Regulations provide no recourse for facilities in these existing contracts. Instead, at the July 15, 2011 workshop, CARB staff recommended that affected parties renegotiate the terms to these agreements. The absence of direction in the Regulation fails to recognize that, without express guidance, entities lack the bargaining power to bring contractual counter-parties to the negotiating table. As one party noted at the July 15, 2011 workshop, until CARB demands a change to these contracts, even the investor-owned utilities believe they lack the authority needed to discuss new terms. While CARB may prefer that contracting parties renegotiate and resolve these issues without administrative intervention, a statement of intent—at a minimum—may help parties who otherwise will be left to bear the full compliance costs of AB 32 regulations with no recourse but to terminate their contract. To assist those facilities with existing contracts not allowing pass-through of GHG compliance costs, the following intent language should be included in CARB's board resolution:

> <u>WHEREAS there are parties with existing contracts which do not allow pass-through of GHG compliance costs, and the implementation of the cap-and-trade program may impose additional costs on parties beyond those that would have been imposed prior to implementation of AB 32;</u>
>
> <u>BE IT FURTHER RESOLVED that the Board intends for parties in existing contracts that do not allow pass-through of GHG compliance costs to renegotiate the terms of these contracts to ensure cost pass-through</u>. (EPUC2)
>
> **Response:** We acknowledge EPUC2's request to include language into the resolution and agree that renegotiation may be the appropriate resolution in most cases. We acknowledged the intent of the commenter's language in the first 15-day changes to the regulation.
>
> In response to this and similar concerns raised by other commenters, in Resolution 11-32 the Board directed the Executive Officer to monitor progress on bilateral negotiations between counterparties with existing contracts that do not have a mechanism for recovery of carbon costs associated with cap-and-trade for industries receiving free allowances pursuant to Section 95891, and to identify and propose a possible solution, if necessary. For fixed-price contracts between independent generators and investor-owned utilities, the Board further directed the Executive Officer to work with the CPUC to encourage resolution between contract counterparties.

Water

I-135. Comment: What is the basis for an allocation of allowances to the Western Area Power Administration? What are the potential benefits and dis-benefits to consumers and program integrity referenced in Appendix A as justification for not allocating allowances to DWR, and on what basis did CARB make these findings? (DWR2)

Response: The regulation does not contain a provision to allocate allowances to WAPA. For the program to work as designed, the cost of carbon must be passed on to the consumer. Sectors that have been identified for allowance allocation have a direct relationship to the consumer that will bear the cost.

I-136. Comment: Why does Appendix A conclude that DWR does not maintain a direct relationship with the end-use consumer, when DWR is the end-use consumer of electricity used by the SWP? (DWR2)

Response: We believe that it is important to capture the emissions associated with water distribution. There are opportunities for reductions in the emissions associated with this activity, and the emissions are not insignificant. The role of water distribution entities (DWR and MWD) in the economic value chain between producers of electricity and end-use consumers of water services is most closely associated with electricity marketers, and their treatment under the regulation is consistent. We believe that it would be inappropriate to provide direct allocations to water distribution utilities for the benefit of end-use customers, because they do not have a direct relationship that would facilitate the return of value in a way that would maintain the marginal incentive of end-use customers to reduce emissions. Further, the emissions associated with water distribution are included in the share of value returned to end-use customers through the electric distribution utilities. We performed an analysis of the distortion created by returning value through electric distribution utilities as opposed to water distribution utilities, and we found the effect to be insignificant.

Nevertheless, in Resolution 11-32 the Board directed the Executive Officer to continue discussions with stakeholders to identify and propose, as necessary, during the initial implementation of the cap-and-trade program, potential amendments to the Regulation regarding the distribution of allowance value associated with cap-and-trade compliance costs from using electricity to supply water, and the expected ability of allowance allocation and other measures to adequately address the incidence of these costs equitably across regions of the State.

I-137. Comment: What is the basis for CARB's conclusion, in Appendix A, that DWR is not well positioned to provide water users with direct compensation?
What standard did CARB use to make the determination that "it is not appropriate to include" DWR in the allocation to the electricity sector (Appendix A)?
Why does CARB state that if DWR used the allowance value, a deterioration of the emissions price signal would result? What is the factual basis for this determination?
Why does CARB state that if DWR received allowances, it would result in lost value for water users?

How does CARB calculate and measure the projected "lost value" to water users if DWR were allocated allowances attributable to the SWP pump-load?
Why did CARB reject DWR's proposal for using allowance value for purposes in furtherance of AB 32 goals (such as renewable energy, energy efficiency and water use efficiency), similar to the electricity distributors' programs currently under development at the California Public Utilities Commission?
What is the basis for the conclusion that the allocation of allowances, attributable to DWR's electricity use, to the IOU's and POU's will result in cost relief to users of the water that DWR delivers?
Why are all electricity-sector emissions allowances, including those attributable to DWR's power use in support of State Water Project, allocated only to investor-owned utilities (IOU) and publicly owned utilities (POU)? (DWR2)

> **Response:** We answered these questions, in the responses to Comments G-115, H-7, I-8, I-41, I-135, and I-136 above and in K-8 and K-9 below.

I-138. Comment: What is the reason CARB did not implement the allowance set-aside for water suppliers as envisioned in the Scoping Plan? (DWR2)

> **Response:** We responded to this comment above, in our responses to Comments I-135 and I-136.

I-139. Comment: If ARB does not exempt Metropolitan from the Cap and Trade Program, then ARB should develop a compliance strategy or memorandum of understanding for Metropolitan as a consumer of wholesale electricity that integrates the imported energy issue into a comprehensive water sector program that includes measures identified in the AB 32 Scoping Plan, such as energy efficiency and renewable energy projects; and defer Metropolitan/water sector measures until 2014 or 2015, after the Cap and Trade Program is implemented. (MWDSC3)

> **Response:** We believe that a comprehensive water-sector program described by the commenter is necessary to meet the 2020 GHG emission reduction target, and to meet other statewide energy/water-related efficiency goals.
> We disagree that Metropolitan's commitment to implement programs suggested in their comment would be a substitute for Metropolitan's inclusion in the first compliance period. We fully expect the water utilities to include these programs in their long-term planning to meet the emission reduction targets, and to meet other statewide energy/water-related efficiency goals.
>
> Nevertheless, in Resolution 11-32 the Board directed the Executive Officer to continue discussions with stakeholders to identify and propose, as necessary, during the initial implementation of the cap-and-trade program, potential amendments to the regulation regarding the distribution of allowance value associated with cap-and-trade compliance costs from using electricity to supply water, and the expected ability of allowance allocation and other measures to

adequately address the incidence of these costs equitably across regions of the State.

I-140. Comment: Metropolitan is a public water supply agency providing a critical public service and is not an electric utility. Metropolitan does not provide electrical service to any load other than its CRA pumping plants. Metropolitan is unique in all of these aspects, and is not comparable to utilities in the electric sector. We strongly believe that Metropolitan should not be included in a Cap and Trade Program that is designed and structured for the electric and industrial sectors. For these reasons, Metropolitan should be exempted from the Cap and Trade Program and its associated compliance obligations, and removed from the category of marketer under the MRR (section 95102(a)(229)) and in the Cap and Trade Regulation (section 95802(a)(153)). Under these definitions, a marketer is defined as "a purchasing/selling entity that takes title to wholesale electricity and is not a retail provider." (MWDSC3)

Response: We do not agree that Metropolitan should be exempt from the program. We responded to this issue in the responses above to Comments I-135 and I-136.

I-141. Comment: The Cap and Trade regulatory scheme is not viable or feasible for a public water supply agency, such as Metropolitan because it is not a marketer of electricity, does not purchase power for resale or for a profit, will receive no cost mitigation for its member agencies (ratepayers), should not be compelled to participate in the carbon market against for-profit market participants as a public agency, the compliance obligation to acquire and surrender allowances will result in highly volatile costs to Metropolitan, Metropolitan's emissions from its imported electricity are already below its 1990 levels, and Metropolitan's role is as a consumer of electricity because of the variability of Metropolitan's energy imports for the CRA and the anticipated increase in the auction price of allowances. (MWDSC3)

Response: We believe Metropolitan is best suited to pass the cost along to member agencies in the same way that Metropolitan is currently passing along the cost for imported electricity.

I-142. Comment: If ARB does not make changes to exclude Metropolitan from the Cap and Trade Program, or defer its compliance until comprehensive water sector specific measures are adopted, the only equitable alternative is to allocate free allowances to Metropolitan as a wholesale utility. Wholesale utilities are essential public services, and like retail electric utilities, they serve a critical public purpose. We believe that it is inappropriate for ARB to deny publicly-owned providers of a critical public resource the same price relief for their customers that the electric sector will enjoy. (MWDSC3)

Response: We do not agree Metropolitan should receive a free allocation of allowances. We responded to this comment above in our responses to Comments I-135 and I-136.

I-143. Comment: The proposed staff approach would treat Metropolitan as a water wholesaler with regards to duties imposed on the water sector, as an electric retailer with regards to Cap and Trade requirements and deny the assistance afforded to electric retailers through free allowances. In our view, this is an inequitable approach. Appendix A (revised July 27, 2011) to the Cap and Trade Regulation provides a paragraph that enumerates ARB's rationale for deciding not to provide free allowances to Metropolitan. Metropolitan disagrees with ARB's decision and the reasoning behind the decision, and considers the way that the decision was communicated to us, i.e. via an Appendix to the Cap and Trade Regulation as inappropriate. We urge the ARB to recognize that a "one size fits all approach" may not work for both Metropolitan and DWR. (MWDSC3)

> **Response:** We responded to this comment in our responses above to Comments I-135, I-136, and I-137.

I-144. Comment: ARB should include water wholesaler in the list of source categories in the Cap and Trade Regulation entitled Emissions without a Compliance Obligation. Modify section 95852.2(b) as follows:

> <u>(18) Importer/Non-Marketer (NM) that purchases electricity generated outside the state of California solely to serve its own load. Importers/NMs that are wholesale water agencies will develop an alternative compliance strategy outside of the Cap and Trade compliance obligation. ARB will work with the wholesale water agencies to develop and implement this plan in 2014-2015.</u> (MWDSC3)

> **Response:** We do not agree that water wholesalers should be included in the list of source categories in section 95852.2(b). We believe it is important to include the emissions associated with all electricity in the program. We responded to this comment in the response above to Comment I-136.

I-145. Comment: The Regulation as currently proposed by ARB staff is inequitable to SWP water consumers, and fails to meet ARB's goals of mitigating rate shock to the end-user. It also raises concern over the SWP consumers' particular exposure to the risk of market failure. Equity can be achieved, along with ARB's goals for the Regulation, by allocating free emissions allowances to the SWC contractors in proportion to their energy charges from the SWP. Modify section 95890 as follows:

> <u>(c) All provisions of this Article applicable to a publicly-owned Electric Distribution Utility shall be applicable to the Contractors of the State Water Project pumping load reported under article 2, section 95111(e), title 17, Greenhouse Gas Emissions Data Report. Where these Contractors are not Water Distribution Utilities, the Allocation provided to the individual Contractor shall be held in trust for its member water distribution utilities.</u> (SWC3)

Response: We do not agree with the comment requesting allowance allocation to the State Water Contract contractors in proportion to their energy charges. It is important that the cost be passed along to the end-user, in order to realize the program's goals.

Nevertheless, in Resolution 11-32 the Board directed the Executive Officer to continue discussions with stakeholders to identify and propose, as necessary, during the initial implementation of the cap-and-trade program, potential amendments to the regulation regarding the distribution of allowance value associated with cap-and-trade compliance costs from using electricity to supply water, and the expected ability of allowance allocation and other measures to adequately address the incidence of these costs equitably across regions of the State.

I-146. Comment: As defined in the proposed regulation, DWR is a First deliverer of electricity because it is expressly deemed an Electricity importer. DWR has complied with the Mandatory Reporting Regulation and has reported in prior years to the same extent as a retail electricity provider. The associated emissions from DWR's imported electricity from specified sources exceed the threshold of 25,000 metric tons CO_2 per year. DWR also purchases power on the CAISO market and its operating costs will be impacted by the carbon cost associated with those purchases. Question has been raised as to whether CARB has jurisdiction over DWR as a state agency, but this comment letter does not take a position on that issue. DWR is considered a Covered Entity by virtue of its activities in the electricity sector. Because of its integration in the electric market, if CARB has the appropriate authority, then it is difficult to see how DWR could be excluded from regulations covering the electric sector. (SWC3)

Response: We agree with the assumption that we have jurisdiction and have appropriate authority to implement this regulation and include DWR.

Miscellaneous

I-147. Comment: Before launching the Cap and Trade market, ARB must analyze the effect of import and export emissions rates on regional electricity markets. ARB should not go forward without a detailed analysis of the possible market changing effects of such default emissions factors. Because emissions factors do not exist today, may vary by location, and may vary depending on whether the delivery is an import or export, the power market's responses to these new economic signals could cause significant changes in power flows and market conditions throughout the Western Electricity Coordinating Council (WECC). In addition, transmission congestion, locational market prices, and the economics of existing or potentially new transmission will be affected. SCE recommends that ARB work with an experienced consultant to model the impacts of its default emissions factors on the power system and Western power markets before finalizing the Cap and Trade market design. (SCE3)

Response: The default emission factor is set pursuant to the MRR. We will continue to work closely with the CEC, CPUC, CAISO, and stakeholders to evaluate the default emission factor to see if it closely approximates the emission rate of the generator that is on the margin. We will monitor changes to reported information pursuant to the MRR and will analyze whether changes are warranted in the future.

I-148. Comment: ARB should clarify how the Cap and Trade Rule's resource shuffling prohibition applies to "Asset-Controlling Suppliers." The term "Asset-Controlling Supplier" is defined in section 95802(a)(13) of the Cap and Trade Rule, and is used in a handful of provisions in the rule. It is not clear how the proposed new prohibition on resource shuffling would apply to asset-controlling suppliers, especially if any of the provisions in section 95111(g)(4) of the MRR are, as discussed above in section I.A.2, intended to function as exemptions to the prohibition on resource shuffling. While electricity procured from an asset-controlling supplier expressly qualifies as a "specified source," see section 95802(a)(258), it is not clear how the concepts of "electricity historically consumed in California" and the "80 percent of net generation" requirement that now are proposed in section 95111(g)(4)(A) of the MRR would apply to asset-controlling suppliers. To prevent resource shuffling by or through asset-controlling suppliers, Powerex encourages ARB to clarify the rule to make it clear that the prohibition applies equally to asset-controlling suppliers and any other electricity generating facility or importer. Additional clarity also should be provided in section 95111(g)(4)(A) of the MRR by making the requirements apply to individual facilities and systems of facilities owned or operated by asset-controlling suppliers. (POWEREX)

Response: Asset-controlling suppliers deliver electricity from sources that have been committed to serve California load. The regulation applies to asset-controlling suppliers in the same way that it applies to other first deliverers of specified sources. Asset-controlling suppliers will need to sign annual attestations and are subject to the same reporting and verification requirements pursuant to the MRR as other covered entities.

I-149. Comment: Rather than requiring electrical distribution utilities to "comply with the requirements of MRR" and obtain a positive verification before being allocated allowances, CARB should utilize the enforcement provisions set forth in the Regulation and in the Mandatory Reporting Regulation to address compliance with reporting requirements, and not restrict the eligibility of the electrical distribution utilities to be allocated allowances to be used for their ratepayers' benefit. A utility should be eligible to receive allocated allowances if it is identified in Table 9-3. The Joint Utilities recommend that the eligibility requirements for an annual allocation of allowances to electrical distribution utilities in section 95890(b) be stricken. Modify section 95890(b) as follows:

~~(b) Eligibility Requirements for Electrical Distribution Utilities. An electrical distribution utility shall be eligible for direct allocation of California GHG allowances if it has complied with the requirements of MRR and has obtained a~~

~~positive or qualified positive emissions data verification statement for the prior year pursuant to MRR~~. (JOINTUTILITIES)

Response: We do not agree with the JOINTUTILITIES. We need to be assured that the covered entity that is eligible to receive free allowance and is obligated to report under the MRR has reported accurately, the report was verified, and they have followed the requirements set forth in the MRR, which apply to all covered entities.

I-150. Comment: The proposed regulation currently requires all IOUs (including any MJRPs) to place all of their allowances directly into the auction. In contrast, POUs would be able to directly use their allowances to meet their own compliance obligation and place the remainder into the auction. For the purposes of these Regulations, MJRPs are more akin to POUs insofar as a MJRP is a vertically-integrated entity operating its own Balancing Authority Area. Furthermore, the MJRP is subject to regulatory jurisdiction by entities other than the California Public Utility Commission (CPUC), and are therefore subject to a different set of resource planning requirements than are the other California IOUs. Accordingly, to accommodate these structural distinctions and avoid direct conflict with its regulatory mandates under other jurisdictions, the MJRP should be given the same compliance flexibility as are the POUs. Doing so will significantly reduce transaction costs associated with an auction which will directly benefit PacifiCorp's customers in California. While PacifiCorp recognizes that it may be the desire of the ARB to send a price signal associated with greenhouse gas emissions, in the case of PacifiCorp, imposing the same requirements on a MJRP as a IOU by requiring PacifiCorp to sell all its allocated allowances and purchase them at auction where its customer base is less than 50,000 customers, more than one-third of whom are eligible for low-income assistance, poses a high and disproportionate burden on PacifiCorp’s customers which is unlikely to appropriately reflect the cost of greenhouse gases. These compliance costs will be higher than those incurred by the IOUs on a per customer basis and any price signal will be out shadowed by the high transaction costs inherent in being a small participant in a large market. (PACIFICOR3).

Response: Although PacifiCorp is an MJRP, it is not similar to POUs, because it does not have an elected or appointed governing body to direct the use of revenue. It is important that the CPUC ensures that PacifiCorp use revenue from the auction to further the AB 32 goals. PacifiCorp will need to purchase allowances like all other privately owned utilities. The market will determine carbon cost; these costs should be passed on to ratepayers. Once the costs are passed on to ratepayers, MJRP, like other IOUs, can seek CPUC approval for either compensating ratepayers, buying allowances, meeting the RPS, or other activities that benefit ratepayers.

Other Electricity-Related Comments

I-151. Comment: Sections 95852(b)(2) through 95852(b)(7) of the Cap-and-Trade regulation should not incorporate the language specific to mandatory reporting, but should instead incorporate it by reference. The approach that the regulations have used have created confusion by attempting to paraphrase the MRR, using language different from that used in the MRR, and created internal inconsistency by, on occasion, summarizing the MRR incorrectly—the language in section 95852 does not exactly match the MRR. Examples include the formula in section 95852(b)(7)(C) being different than the formula in section 95111(b)(5) in leaving out deductions for replacement electricity, and emissions from a specified source with emissions exceeding the default emissions factor are counted in section 95852(b)(7)(B) at the default emissions rate while being counted at the actual specified emissions rate in section 95111(b)(2) of the MRR. Section 95852(b) should be changed to incorporate the MRR by reference as much as possible to avoid confusion in compliance obligation. Lastly, section 95852(b) appears to include sources in California, so a calculation method for in-state resources should be included for completeness. Modify section 95852(b) as follows:

> (2) The following criteria must be met ~~for~~ by first deliverers of electricity deliveries to calculate their compliance obligations for imported electricity from specified facilities or units in jurisdictions that are not approved for linkage pursuant to subarticle 12 and which do not involve replacement electricity: ~~based on an ARB facility specific emission factor specified pursuant to MRR section 95111 less than the default emission factor for unspecified electricity specified pursuant to MRR section 95111:~~
>
> > (A) Electricity deliveries must meet the requirements of ~~be reported to ARB pursuant to~~ MRR section 95111(a)(4);
> >
> > (B) ~~The first deliverer must be the facility operator or have ownership or contract rights to electricity generated by the facility or unit claimed;~~ Electricity deliveries must meet the requirements of direct delivery of electricity as defined in MRR section 95102(a); and
> >
> > (C) First deliverers must ~~report electricity~~ calculate emissions from ~~specified sources to ARB using the ARB specified source identification number assigned to the source~~ in accordance with ~~pursuant to~~ MRR section 95111(b)(2).~~; and~~
> >
> > ~~(D) If there are other parties within the contract chain of custody, then the original source of generation and quantity of MWhs to be delivered under the original contract must be identified within the entire contract chain. The quantity of electricity delivered, and for which an ARB facility specific emission factor specified pursuant to MRR section 95111 is claimed, cannot exceed the original amount under ownership or contract rights reported pursuant to section 95852(b)(2)(A).~~
>
> (3) Replacement electricity that substitutes for electricity from a variable renewable resource qualifies for the ARB specific emission factor ~~specified pursuant to MRR section 95111 of the variable renewable resource~~ under the following conditions:

(A) Replacement electricity must meet the requirements of MRR section 95111(a) ~~First deliverers of replacement electricity have a contract, or ownership relationship, with the supplier of the replacement electricity, in addition to a contract with the variable renewable resource~~;

(B) The amount of the reported replacement electricity does not exceed the amount for the reported annual variable renewable resource; and

(C) The rReplacement electricity ~~with an~~ emission factors are calculated in accordance with ~~greater than the default emission factor for unspecified electricity specified pursuant to~~ MRR sections 95111(b)(1) through 95111(b)(5). ~~is not eligible to receive an emission factor of zero metric tons CO2e/MWh. For contracts that use replacement electricity for which the emission factor is greater than the default emission factor for unspecified electricity, the difference between the emission factor from the replacement electricity and the default emission factor for unspecified electricity will be used to calculate emissions with a compliance obligation.~~

~~(4) Claims to resources with zero direct emissions, emissions without a compliance obligation, or emissions calculated using a lower emissions factor than the default emissions factor for unspecified electricity specified pursuant to MRR section 95111, including renewable resources other than variable renewable resources must demonstrate, pursuant to MRR, direct delivery of electricity as defined in section 95802.~~

(4~~5~~) Electricity generated from use of biomethane must comply with section 95852.2, and must meet verification requirements for use of biomethane pursuant to MRR.

(5~~6~~) Qualified Exports. Emissions from qualified exports claimed by a first deliverer may be subtracted from the first deliverer's compliance obligation for imported electricity in accordance with MRR section 95111(b)(5) only if the electricity meets the definition of qualified export in MRR section 95102(a). ~~is exchanged within the same hour and by the same PSE. It is not necessary for the electricity to enter or leave California at the same intertie. Qualified exports shall not result in a negative compliance obligation for any hour.~~

(6~~7~~) The compliance obligation for first delivers for ~~(CO2e covered) is calculation based on the~~ emissions from electricity deliveries from jurisdictions that are not approved for linkage pursuant to subarticle 12 is to be calculated in accordance with MRR section 95111(b)(5).

~~A) Emissions which result from specified electricity deliveries (CO2e specified) will be assigned the facility emission factor, determined by ARB, for electricity deliveries meeting the requirements of section 95852(b)(2) through (5);~~

~~1. Specified deliveries meeting the requirements of section 95852(b)(2);~~

~~2. The adjustment for replacement electricity associated with the variable renewable electricity pursuant to section 95852(b)(3);~~

~~3. The specified electricity meeting direct delivery requirements pursuant to section 95852(b)(4); and~~

~~4. The specified electricity generated from the use of biomethane which meets the requirements pursuant to section 95852.2.~~

~~(B) All deliveries of electricity not meeting the requirements of section 95852(b)(2) through (5) will have emissions calculated using the default emission factor for unspecified electricity pursuant to section 95111 of MRR (CO2e unspecified).~~

~~(C) Emissions resulting from qualified exports (CO2e qualified exports) will be subtracted from the compliance obligation pursuant to section 95852(b)(6). Compliance Obligation in CO2e covered=CO2e specified + CO2e unspecified-CO2e qualified export~~

(7) The compliance obligation for electric generation and cogeneration facilities or units within California for emissions from electricity generated is to be calculated in accordance with MRR section 95112. (SEMPRA3)

Response: Sections 95852(b)(2) through 95852(b)(7) were modified extensively in the Second 15-day Change Notice. The formula to determine which reported emissions result in a compliance obligation are now clarified and contained in the cap-and-trade regulation. Specific details pertaining to reporting requirements for each portion of the formula remain in the MRR. We believe the text is now consistent with the MRR.

I-152. Comment: ARB's proposed 15-day modifications of the cap-and-trade regulation are flawed by 1) allowing replacement power only for variable renewable resources, and 2) requiring the replacement power to be from the same balancing authority. The potential problems of double-counting should not drive the ARB cap-and-trade regulation to conflict to State law; double-counting can be addressed at the time of linking. If the requirement is for tracking purposes, it is unclear how replacement power from the same balancing area is any easier to track than power from any other balancing authority. The WREGIS system already exists to track RPS-eligible renewable energy and replacement electricity throughout the WECC. There are three workable changes ARB should consider to comply with State law concerning renewables and to be consistent with the Scoping Plan that assigns GHG reductions to all renewable energy. First, the best alternative would be to eliminate the requirements that 1) replacement electricity apply only to variable renewable resources and instead apply to all renewable resources, and 2) replacement electricity be from the same balancing authority as the renewable resource. This approach would allow for the rebundling of RECs with any imports already approved by the CEC and CPUC. In addition, it would allow for future projects, including transactions using unbundled RECs, that may be consistent with the restrictions of the RPS program as modified by SB x1 2. This would result in replacement electricity being treated as having zero emissions, to reflect the fact that the underlying renewable is resulting in a backing down of emissions elsewhere in the region. Commensurate with this structure, renewable power that is sold without RECs becomes “null power” and like unspecified power imported to California should be assigned a default GHG emission rate for compliance obligation purposes. This approach would be consistent with the contractual terms of existing contracts, section 399.12, and expectations of the parties who signed the contracts. A second approach would be to "grandfather" contracts entered into prior to the start of the cap-and-trade program and add more flexibility to ARB's approach requiring replacement electricity to be from the same balancing authority. With grandfathering, the regulation would state that for contracts entered into before the start of the cap-and-trade program, replacement power could be used consistent with CEC and CPUC approved rebundling. Such contracts would be supplied to ARB and for that list of contracts, the replacement power would not be required to be from the same balancing authority, but from a source or sources approved by the CEC and/or CPUC. For grandfathered contracts, this would result in replacement electricity being treated as having zero emissions, to reflect the fact that the underlying renewable is resulting in a backing down of emissions elsewhere in the region. The electricity from the renewable resource without the green attributes would be assigned the default rate and could not be used as a specified zero GHG resource. A third approach would be an adjustment to other elements of the cap-and-trade regulation and would not require significant changes to the definition of replacement electricity except to deal with small balancing authorities. The approach would adjust the annual allowance budgets for Calendar Years 2013-2020 in section 95841 to account for the zero GHG renewable resources that are not being counted as zero GHG under the cap-and-trade program. In the cap-and-trade regulation adopted by ARB in December 2010, the annual allowance budgets were dramatically reduced to account for emissions in covered sectors that were not covered by the cap-and-trade regulation. This approach would reverse the process and account for reduced GHG emissions of the out-of-state renewables that were not being counted in the cap-and-trade program. The adjustment to the program cap would take place annually based on the prior year energy production by the renewable resources that are not being counted as zero GHG. The second part would be to provide the allowances to the electricity importer for that replacement electricity that is not counted as zero GHG under the cap-and-trade program. Once the prior year production of renewable energy not counted as zero GHG is determined, ARB would place the allowances into the importers' holding accounts. This approach is also "second best" since it is complicated and relies on lagged data. Modify sections 95802(a)(237), 95841, and 95780(f) and (g) as follows:

> (237) "Replacement electricity" means electricity delivered to a first point of delivery in California <u>in accordance with State Renewable Portfolio Standards</u> to replace electricity from ~~variable~~ <u>RPS-eligible</u> renewable resources in order to meet hourly load requirements. The electricity generated by the ~~variable~~ renewable energy facility and purchased by the first deliverer is not required to meet direct delivery requirements. ~~The physical location of the variable renewable energy facility busbar and the first point of receipt on the NERC E-tag for the replacement electricity must be located in the same balancing authority area.~~

Or

> (237) "Replacement electricity" means electricity delivered to a first point of delivery in California to replace electricity from ~~variable~~ <u>RPS-eligible</u> renewable

resources in order to meet hourly load requirements. The electricity generated by the ~~variable~~ renewable energy facility and purchased by the first deliverer is not required to meet direct delivery requirements. The physical location of the ~~variable~~ renewable energy facility busbar and the first point of receipt on the NERC E-tag for the replacement electricity must be located in the same balancing authority area, or if a balancing authority is small, an adjacent balancing authority, for RPS contracts signed after the start of the cap-and-trade program. For RPS contracts signed prior to the start of the cap-and-trade program, replacement electricity must be delivered to California in accordance with the State Renewable Portfolio Standards.

Or

(237) “Replacement electricity” means electricity delivered to a first point of delivery in California to replace electricity from ~~variable~~ RPS-eligible renewable resources in order to meet hourly load requirements. The electricity generated by the ~~variable~~ renewable energy facility and purchased by the first deliverer is not required to meet direct delivery requirements. The physical location of the ~~variable~~ renewable energy facility busbar and the first point of receipt on the NERC E-tag for the replacement electricity must be located in the same balancing authority area, or if the balancing authority is small, an adjacent balancing authority.

And add to section 95841:

The annual allowance budgets shown in Table 6-1 will be adjusted upward in each compliance year for the energy from renewable resources developed and approved pursuant to the State’s RPS program that do not have replacement electricity meeting the requirements of section 95802 and do not affect the compliance obligations in section 95852. The amount of energy will be based on the positive or qualified positive emissions data verification statement for the year for which the compliance obligation is calculated.

And

(f) Allocation to Electricity Importers for RPS-eligible Renewable Energy Requiring Allowance Surrender

(1) The Executive Officer will place an annual individual allocation in the holding account of each eligible entity on or before the surrender dates for compliance for each calendar year 2013-2020.

(2) The total amount of allowances shall be calculated consistent with the adjustment to the program cap in section 95841

(g~~f~~) Auction Proceeds for AB 32 Statutory Objectives. All remaining allowances not allocated for uses specified in sections 95870(a) through (f~~e~~) will be designated for sale at auction. The proceeds from the sale of these allowances will be deposited into the Air Pollution Control Fund and will be available for appropriation by the Legislature for the purposes designated in California Health and Safety Code Sections 38500 et seq. (SEMPRA3)

Response: We agree and we made significant modifications to section 95852(b) regarding the treatment of electricity from renewable resources and the role of RPS eligible electricity in reducing the compliance obligation of an electricity importer. We deleted section 95802(a)(237), the definition of “replacement electricity.” Our new approach relies on an RPS adjustment which is the subject of new section 95852(b)(4). The RPS adjustment is a quantity of emissions calculated as the product of the default emission actor and the megawatt-hours of electricity generated at an “eligible renewable energy resource” (as newly defined), and meeting the requirements of new section 95852(b)(4).

Before making these modifications, we took an approach in which certain delivered quantities of electricity from non-renewable resources (replacement electricity) would be deemed to have an emission factor of an associated variable renewable resource. With the modifications, the regulation now allows for an adjustment in an electricity importer’s total compliance obligation based on the amount of RPS-eligible electricity procured or imported that is not directly delivered to California. If RPS eligible electricity is directly delivered, it receives its actual emission factor, which in many cases is zero.

Our new approach means that we need not consider “firming and shaping” electricity. It also means that the compliance obligation of an electricity importer may be reduced based on the importer’s electricity procured from an eligible renewable energy resource, regardless of whether the resource is variable (or intermittent.) Furthermore, because the RPS adjustment is now a term that is subtracted out of the total compliance obligation equation for importers, there is no connection to any electricity that replaces renewable electricity. This means there is no longer a requirement that replacement electricity originate in a particular balancing authority.

In considering electricity from renewable resources, we sought a balance between recognizing the value of investments in renewable electricity under the RPS mandate and our need to ensure compatibility with WCI partners when California links with other jurisdictions. We also sought to limit the potential for leakage or “double-counting” of the fact that renewable electricity may be generated with zero, or very low, GHG emissions.

Initially we believed that the correct balance required that replacement electricity be allowed only for variable renewable resources, and that replacement electricity come from generators located in the same BAA as the renewable resource. Through informal discussions as well as consideration of comments, we came to the conclusion that these restrictions would not necessarily consider utility investment in RPS eligible electricity and would not necessarily facilitate compatibility with linked jurisdictions more so than our modified approach.

We had initially considered replacement electricity only for variable resources, which, due to intermittency, cannot be directly delivered because they cannot be scheduled across BAAs, except in a few limited cases. However, other renewable resources cannot always be scheduled into California due to transmission constraints or other factors. We realized that there would be greater equity for utilities and other electricity importers if the non-variable RPS-eligible electricity could also reduce an importer's compliance obligation. To facilitate linkage, and minimize double-counting opportunities, we added new section 95852(b)(4)(E). This new section disallows an RPS adjustment for electricity generated at an eligible renewable energy resource in a linked jurisdiction. We believe that the modifications to sections 95802 and 95852 have met the concerns expressed in the comments above, and have rendered moot their specific proposals for modifications to the regulation.

I-153. Comment: If ARB chooses not to make any changes to its cap-and-trade and mandatory reporting regulations regarding replacement electricity, then Table 9-3 is incorrect since it has as an underlying assumption that all renewable electricity that complies with the State's 33 percent RPS has zero GHG emissions. Under the 15-day modifications, 1.2 million MWhs of wind energy per year that SDG&E has contracted for would have a compliance burden. Under the compliance burden approach outlined in Appendix A to the 15-day modifications, SDG&E should be provided free allowances for this electricity. SDG&E cannot provide proposed modifications to Table 9-3 since it does know what replacement electricity of other electric distribution utilities is not counted as zero GHG electricity. (SEMPRA3)

Response: We removed the definition for "Replacement electricity" and we included a provision, 95852(b)(4), to recognize RPS-eligible electricity. Eligible RPS electricity can reduce the first deliverer's compliance obligation, pursuant to the requirements contained in section 95852(b)(4).

I-154. Comment: Section 95814(a) lists types of entities that "may qualify as voluntary associated entities" including "an entity that does not meet the requirements of sections 95811 and 95813 that intends to purchase, hold, sell, or voluntarily retire compliance instruments." The Eight Utilities fall squarely within the definition of section 95814(a)(1). Pursuant to the regulation, they plan to apply to the Executive Director for approval as VAEs, due to the importance of the allowance allocation process. However, the Eight Utilities recommend that ARB add the following underlined language in order to provide greater clarity for these entities which are directly affected by this regulation. Based on the Eight Utilities' review of the proposed regulations, all EDUs registering as VAEs would be subject to the proposed regulations involving entity registration, allowance allocations, allowance consignment, the use of allowance value, and annual reporting. Modify section 95814(a)(4) as follows:

(4) An Electric Distribution Utility that receives an annual allocation of allowances pursuant to section 95870(d) but does not meet the requirements

of sections 95811 and 95813. (EIGHTUTILITIES)

Response: We agree that some Electric Distribution Utilities may not meet the definitions of sections 95811 and do not need to become opt-in covered entities pursuant to 95813 in order to purchase, hold, sell, or voluntarily retire compliance instruments. However, we do not believe that the additional text proposed by the commenter is appropriate because some EDUs are in fact covered entities due to also acting as first deliverers of electricity.

J. ENFORCEMENT

Penalties

Clarification Needed

J-1. (multiple comments)
Comment: It is not clear in section 96014(c) that it is a violation when someone intentionally misleads the ARB in terms of the actions listed in (1) through (4), as compared to the situation when simply a mistake has been made. Modify section 96014(c) as follows:

> (c) It is a violation to submit any record, information or report required by this article that <u>knowingly</u>: (CACC2)

Comment: Section 96014(c) added a new enforcement provision to the Cap and Trade Regulations to identify violations of a more egregious nature. However, it would be best to clarify this section by adding the word “knowingly” in the lead sentence such that it reads. Modify section 96014(c) as follows:

> (c) It is a violation to submit any record, information or report required by this article that <u>knowingly</u>: (UNITEDAIRLINES2)

Comment: CARB states in the 15-day Notice that Section 96014(c) was added "to clarify that any act of deception in working with ARB will subject an entity to additional penalties." Specifically, Section 96014(c)(2) refers to any submission that "[m]akes any false, fictitious or fraudulent statement or representation," and Section 96014(c)(4) refers to any submission that "[o]mits material facts from a submittal or record." CSCME respectfully submits that the term "knowingly" should be added to both of these provisions to ensure that each provision addresses deceptive rather than inadvertent acts. (CSCME4)

Comment: CARB states in the 15-day Notice that it modified Section 96014(b) to clarify that entities will not accrue daily violations for failing to surrender a compliance instrument on the required day until at least forty-five days have passed, in order to "allow greater time to obtain the compliance instruments and thus maintain stability of the market." CSCME agrees that this clarification is reasonable. (CSCME4)

> **Response:** We did not implement this change. The Health and Safety Code contains different maximum penalty amounts for violations that occurred under various mental states, including strict liability, negligence, knowing acts, and intentional acts. See Health and Safety Code sections 42400-42402.3.

Provide Flexibility

J-2. (multiple comments)
Comment: Section 96013 retains the reference to the penalty provisions in Health and Safety Code section 38580. These provisions provide a menu of criminal and civil penalties that can range from fines of $1,000 to $1,000,000, and up to a year in county jail or state prison. These fines are between 200 to 100,000 times expected allowances prices. Such excessive penalties are not necessary and will not serve to deter bad actors. SCE recommends that ARB develop a more reasonable fine structure. (SCE3)

Comment: With respect to penalties and violations, as specified in sections 96013 and 96014, WSPA believes that the degree of culpability should be an express component in determining penalty amounts, and that determining penalties on a "per ton per day" basis would result in potential penalties that are exponentially high in relation to any harm. WSPA proposes that ARB revise sections 95858, 96013 and 96014 as shown in Attachment F, to incorporate the concepts summarized above and to provide additional clarity in section 95858. (WSPA3)

> **Response:** We revised the penalty structure to provide that penalties for unsurrendered allowances accrue every 45 days, rather than having them accrue daily. This provides flexibility to the compliance entity to obtain additional allowances either through an auction or purchase of allowances through the allowance price containment reserve, and also reduces the potential liability for compliance entities.

J-3. Comment: NCPA is concerned that the calculation of a separate violation for each single compliance instrument is excessive, especially given the other provisions in the regulation that address noncompliance, including the requirement to surrender four times the amount of an unmet compliance obligation. Accordingly, NCPA joins with the Joint Utilities in urging CARB to address violations of the compliance obligation in a realistic manner and consider each 1,000 instruments (or portion thereof) a single violation. Additionally, NCPA urges the revisions to section 96014(b) addressed in the Notice to be reincorporated into the revised regulation; that is the modification that provides that violations accrue every 45 days, rather than on a daily basis for compliance instruments that remain unsurrendered. Modify section 96014 as follows:

> (a) If an covered entity fails to surrender a sufficient number of compliance instruments to meet its compliance obligation as specified in sections 95856 or 95857, and the procedures in 95857(c) have been exhausted, there is a separate violation of this article for each 1,000 required compliance instruments, or portion thereof, that have~~s~~ not been surrendered, or otherwise obtained by the Executive Officer under 95857(c).
> (b) There is a separate violation for each day or portion thereof after the compliance date that each required compliance instrument has not been surrendered. There is a separate violation for each 45-day period or portion thereof after date determined pursuant to section 95857(b)(4~~) the end of the~~

~~Untimely Surrender Period~~ that each 1,000 required compliance instruments, or portion thereof, have~~s~~ not been surrendered. (NCPA3)

Response: We did not bundle the allowances into 1,000 allowance units for purposes of determining penalties. One metric ton of CO_2e is the basic unit for both reporting under the MRR and for compliance or trading under the cap-and-trade regulation. It is therefore an appropriate unit by which to count violations under both rules. Moreover, Health and Safety Code section 38580(b)(3) authorizes ARB to define penalties on a per-unit basis, proportional to the conduct, rather than defining violations purely in terms of days. We revised the penalty structure to provide that penalties for unsurrendered allowances accrue every 45 days, rather than having them accrue daily. This provides flexibility to the compliance entity to obtain additional allowances either through an auction or purchase of allowances through the allowance price containment reserve, and also reduces the potential liability for compliance entities.

J-4. Comment: Penalties to entities failing to meet their compliance obligation should not remove additional allowances from the market even if the removal is temporary. NextEra agrees with the magnitude of the penalty that would be imposed on an entity that fails to meet their compliance obligation in a “timely manner.” The 4 to 1 multiplier is an effective deterrent and is appropriate in this type of situation. However, NextEra would urge ARB to change the mechanism for implementing the penalty. We are not implying the shortfall in the compliance obligation should be satisfied with anything but the correct amount of allowances. One allowance should be surrendered for each ton of GHG emitted to cover the shortfall. We feel the penalty portion of the enforcement should be collected in the form of a monetary payment rather than the temporary surrender of additional allowances. The removal of the additional allowances to satisfy the penalty has potentially unintended consequences. The removal of allowances not needed to meet a compliance obligation could place an additional burden on all market participants, not just the entity responsible for the infraction. The resulting increase in the scarcity of allowances could result in an increase to allowance prices. A monetary penalty has the desired effect on the offending entity without causing potential hardship on the rest of the allowance market. (NEXTERAENERGY2)

Response: The additional allowances are not a penalty. Rather, they ensure environmental integrity of the regulation as an additional incentive to ensure compliance with the regulation’s surrender obligations. The allowances surrendered pursuant to section 95857 will be returned to the Auction Holding account for sale at a future auction, thus reducing the likelihood that the additional surrender obligation will adversely impact the market.

Layering of Penalties

J-5. Comment: We do not believe that it would be appropriate for covered entities to be subject to duplicative or overlapping penalties. The program’s market-oriented penalty structure (e.g., the 4:1 allowance or offset relinquishment under applicable circumstances) should suffice to ensure effective program operation. As drafted, the program still creates overlapping jeopardy for covered entities by subjecting them potentially to a number of daily, or per-compliance-instrument (i.e., per ton), penalties. The language also does not sufficiently protect covered entities that are working in good faith with qualified verifiers. We appreciate that the staff has considered selective use of language that could limit more serious penalties to the more significant scenarios in which fraud or other bad intent is present. However, this language does not yet displace other penalties. We believe that such differentiation among penalty types is very important so as not unduly to punish good actors. We suggest that the staff continue to work with interested stakeholders to identify different penalty scenarios and to insert clarifying language into the relevant sections to ensure that covered entities are not subject to overlapping penalties. (CCC2)

> **Response:** ARB has modified the enforcement provisions in the cap-and-trade regulation to address the concern of overlapping penalties across both the MRR and the cap-and-trade regulation. As modified, violations for under-reported tons and failures to measure in the manner required by the MRR will be dealt with solely under the MRR enforcement provisions. In terms of the cap-and-trade regulation, once a covered entity reports its emissions under the MRR, those emissions are then verified, and the covered entity receives either a positive, qualified positive, or adverse emissions verification statement. In the event of either a positive or qualified positive verification statement, the entity's cap-and-trade compliance obligation is equal to one allowance for each ton emitted. If a covered entity receives an adverse verification statement under the MRR, ARB will calculate and assign the covered entity's emissions level pursuant to section 95131(c)(5) of the MRR, and that level will become the covered entity's cap-and-trade compliance obligation. In either instance, if the covered entity is found (either in the current year or in a later year) to have under-reported its emissions, the penalty for the under-reporting will be wholly contained in the MRR—without the possibility of overlapping cap-and-trade penalties. On the other hand, failure to surrender sufficient compliance instruments, based on either an assigned emissions level or on a positive or qualified positive emissions level, will be subject to the penalty contained in the cap-and-trade regulation.
>
> In addition, we revised the penalty structure to provide that penalties for unsurrendered allowances accrue every 45 days, rather than having them accrue daily. This provides flexibility to the compliance entity to obtain additional allowances either through an auction or purchase of allowances through the allowance price containment reserve, and also reduces the potential liability for compliance entities.

J-6. Comment: In evaluating the proposed enforcement provisions, PG&E takes the position that potential liability should be adequate to assure compliance, but should not be so high that the liability would exceed any possible environmental harm. Given the high rates of compliance with local air district regulations governing emissions from stationary sources, it makes sense that the potential liability for violations of the MRR and Cap and Trade rules should be in generally the same range as the existing penalty exposure for violations of air district rules. The level of detail required by the MRR and Cap and Trade rules, coupled with the complexity of modern power plants, and the quantity of GHG emissions (measured in metric tons of CO_2e), creates extremely large numbers of potential violations, which would lead to unreasonably high potential liability if not addressed appropriately in the Regulations. For that reason, PG&E appreciates ARB's elimination of the "per ton, per day" potential penalties that were included in earlier versions of the enforcement language. PG&E also supports ARB's amendments to section 95857(d) stating that three fourths of the allowances surrendered as a penalty for untimely surrender are transferred to the Auction Holding Account. (PGE4)

> **Response:** This comment does not request any additional modification to the regulatory language. We appreciate the commenter's support for modifications already made. Regarding the portion of the comment discussing overlapping between the MRR and the cap-and-trade regulation, see the response to Comment J-5.

Allow More Time to Purchase Allowances

J-7. Comment: SMUD appreciates the changes to the proposed penalty structures for the Cap and Trade program that are captured in the 15-day language. In particular, allowing an effective 'grace period' while the untimely surrender process is dealing with a shortfall of surrendered emissions, prior to establishing daily penalties for each compliance instrument remaining short helps to ensure a reasonable and effective penalty structure for the cap and trade program. (SMUD3)

> **Response:** This comment does not request any additional modification to the regulatory language. We appreciate the commenter's support for modifications already made.

Ensure Strong Penalties

J-8. Comment: We recommend the language in section 96014 be expanded to recognize other types of violations beyond failure to submit sufficient compliance instruments, and submittal of false documentation. Other potential violations include, but are not limited to, failure to register, failure to comply with requests for information, failure to retire Offsets, etc. The rule should provide enforcement authority over failure to comply with any requirements of the program unless specifically exempted. (CAPCOA2)

> **Response:** We note that the violations specified in section 96014(c) are in addition to other violations of the regulation (see section 96014(d)). Moreover, Health and Safety Code section 38580 authorizes ARB to enforce against any violation of any regulation. This statutory provision authorizes ARB to enforce against any failure to comply with any requirement of the program, and the specifically defined violations in section 96014 do not limit this statutory authority.

J-9. Comment: In the 15-day changes, ARB has revised section 96014 in ways that we believe substantially undermines the enforceability of the program, and is likely to compromise the ultimate objective of reducing emissions. Specifically, Days of Violation. We strongly recommend you reinstate the deleted language that specified that "each day or portion thereof in which any other violation of this Article occurs is a separate offense." Further, at a minimum, the counting of violation days should begin as soon as the compliance target is exceeded, not delayed until five days after the reporting period ends. Ideally, the number of days of violation should be the number of days in the compliance period subject to reduction according to the proof presented by the entity. For example, if an entity has submitted data in year Y, and surrenders insufficient compliance instruments on November 1 in year Y+1 (as required in 95856(d)), the violation should be counted based on the number of days in the compliance period for which the surrendered instruments were insufficient. (CAPCOA3)

> **Response:** We believe that the statutory authority in Health and Safety Code section 38580 authorizes ARB to enforce against any failure to comply with any requirement of the program, and the specifically defined violations in section 96014 do not limit this statutory authority. Regarding the portion of the comment seeking reinsertion of number of days of violation, we believe that the revisions providing that penalties for unsurrendered allowances accrue every 45 days, instead of having them accrue daily, provide a sufficient deterrent while simultaneously providing flexibility to the compliance entity to obtain additional allowances, either through an auction or by purchasing them through the allowance price containment reserve. Therefore, we did not make the suggested modifications.

J-10. Comment: As currently proposed, section 96014 recognizes only two types of violations: failing to submit sufficient compliance instruments, and submitting any false document or one omitting a material fact. There are potentially many other violations of the program that should be subject to penalty. For example: participating in the program without having registered with CARB, failure to provide records requested by CARB, failure to comply with the six-year rotation requirement; failure to retire offsets used as CARB offsets, etc. CARB needs to maintain the ability for civil and criminal prosecution of any violation of the program. (SCAQMD4)

> **Response:** We believe that the statutory authority in Health and Safety Code section 38580 authorizes ARB to enforce against any failure to comply with any requirement of the program, and the specifically defined violations in section 96014 do not limit this statutory authority.

J-11. Comment: We are concerned that the emphasis on deliberate, intentional, fraudulent reporting dilutes the impact of the strict liability offense of simply submitting an inaccurate report. Our experience has shown that most Cap and Trade violations will be based on inaccurate and/or untimely reporting. It is extremely difficult to establish that the inaccurate reports were the product of fraud or trickery. It is imperative that the program participants know that inaccurate and untimely reporting may be subject to the highest penalties authorized by law. (SCAQMD4)

> **Response:** Inclusion of section 96014(c) does not remove the underlying strict liability nature of the enforcement provisions in the cap-and-trade regulation. Moreover, violations that occur through inaccurate and/or untimely reporting of GHG emissions will be dealt with under the MRR. Violations for under-reported tons and failures to measure in the manner required by the MRR will be dealt with solely under the MRR enforcement provisions. In terms of the cap-and-trade regulation, once a covered entity reports its emissions under the MRR, those emissions are then verified, and the covered entity receives either a positive, qualified positive, or adverse emissions verification statement. In the event of either a positive or qualified positive verification statement, the entity's cap-and-trade compliance obligation is equal to one allowance for each ton emitted. If a covered entity receives an adverse verification statement under the MRR, ARB will calculate and assign the covered entity's emissions level pursuant to section 95131(c)(5) of the MRR, and that level will become the covered entity's cap-and-trade compliance obligation. In either instance, if the covered entity is found (either in the current year or in a later year) to have under-reported its emissions, the penalty for the under-reporting will be wholly contained in the MRR—without the possibility of overlapping cap-and-trade penalties. On the other hand, failure to surrender sufficient compliance instruments, based on either an assigned emissions level or on a positive or qualified positive emissions level, will be subject to the penalty contained in the cap-and-trade regulation.

J-12. Comment: Section 96014 has been modified to delete the catch-all requirement that "each day or potion thereof in which any other violation of this Article occurs is a separate offense." We strongly recommend this language be reinstated. (SCAQMD4)

> **Response:** This language was revised in the second 15-day changes to the regulation to reflect that penalties will accrue every 45 days, instead of daily. We believe that the statutory authority in Health and Safety Code section 38580 authorizes ARB to enforce against any failure to comply with any requirement of the program, and the specifically defined violations in section 96014 do not limit this statutory authority.

J-13. Comment: We urge ARB to retain the robust penalty provisions in the draft Regulation to safeguard the environmental integrity of the program. Employing an allowance multiplier sends a clear, transparent signal to market participants that noncompliance will never be in their economic interest. We are not persuaded by suggestions from other stakeholders that requiring violators to submit excess allowances as part of their untimely surrender obligation penalizes all participants—by removing allowances from the market and driving up allowance prices—and should therefore be eliminated. ARB's focus should remain on designing a program that sends the strongest possible signal to encourage compliance. Eliminating the automatic penalty provision in section 95857(b)(2) will push all of the enforcement decisions into the murkier waters of administrative penalties, which will introduce uncertainty and require significantly more time and resources on the part of ARB. Moreover, ARB's revised approach to allocating excess allowances eliminates any residual concern related to the automatic penalty provision. By making excess allowances submitted by noncompliant entities available at a subsequent auction, ARB will retain the strong deterrent of a multiplier while guarding against any unwanted pressure on allowance prices. (KUSTIN16)

> **Response:** We believe that we designed the cap-and-trade regulation to provide for sufficient deterrence to non-compliance, and that the penalty provisions are both robust and protective of the integrity of the program. See also the responses to Comments J-10, J-11 and J-12. It is unclear what the commenter means by referring to "administrative penalties." As provided in Health and Safety Code section 38580(b)(2):
>
> > "Any violation of any rule, regulation, order, emission limitation, emissions reduction measure, or other measure adopted by the state board pursuant to this division shall be deemed to result in an emission of an air contaminant for the purposes of the penalty provisions of Article 3 (commencing with Section 42400) of Chapter 4 of Part 4 of, and Chapter 1.5 (commencing with Section 43025) of Part 5 of, Division 26."
>
> As such, there is no provision in the cap-and-trade regulation for administrative penalties.

J-14. Comment: NextEra agrees with ARB's position on intentional misrepresentation of data associated with an offset project. Any intentional misrepresentation of an offset project's GHG mitigation should be dealt with harshly. Also any attempt to acquire an offset credit after a renewable energy credit has been sold for the same power generation must not be permitted. These actions have real financial and environmental implications. Any such actions undermine the integrity of the program and the offset system. It also provides an unfair economic advantage to those committing the act. We agree with ARB and other stakeholders that strict penalties and legal action is warranted in those situations. (NEXTERAENERGY2)

> **Response:** The comment does not request any specific changes. We appreciate the commenter's support and agree that enforcing the requirements of the regulation is critical to ensuring the integrity of the cap-and-trade and compliance offset programs.

J-15. Comment: The rule establishes a separate day of violation for each day after the reporting period. In many cases, this will result in a relatively small number of days of violation. The Health and Safety Code is based on actual days of violation (as opposed to pounds of pollution or numbers of compliance instruments), so this provision is of critical importance. If an enforcement action is taken to court, the extent to which actual days of violation can be established will be persuasive to a judge. Accordingly, in order to ensure adequate deterrent value in cases which may be based on negligent or intentional conduct, we recommend that the rule provide that a separate day of violation is established for each day of the applicable compliance period unless the program participant can establish compliance for each of those days. The violations continue until final compliance is achieved. This will provide an adequate number of days of violation to deter future misconduct at the facility and throughout the regulated community. (SCAQMD4)

> **Response:** We believe that the statutory authority in Health and Safety Code section 38580 authorizes ARB to enforce against any failure to comply with any requirement of the program, and the specifically defined violations in section 96014 do not limit this statutory authority. Regarding the portion of the comment seeking reinsertion of number of days of violation, Health and Safety Code section 38580(b)(3) authorizes ARB to define penalties on a per-unit basis, proportional to the conduct, rather than defining violations purely in terms of days. As such, we believe that the revisions providing that penalties for unsurrendered allowances accrue every 45 days, instead of having them accrue daily, provide a sufficient deterrent while simultaneously providing flexibility to the compliance entity to obtain additional allowances, or by purchasing them through the allowance price containment reserve. We did not make the suggested modifications.

Consideration of Circumstances

J-16. Comment: CARB's revision to Section 96013 requires it to "consider all relevant circumstances, including the criteria in Health and Safety Code section 42403(b)" in determining any penalty amount for failing to surrender the appropriate number of compliance instruments in a timely manner. This minor clarification is appropriate, because it highlights the need for CARB to consider circumstances in determining a penalty amount. Factors mentioned in HSC Section 42403(b) include the extent of any harm caused, the nature and persistence of a violation, the frequency of past violations, and the financial burden to the defendant. Explicit reference to consideration of such factors helps ensure consistency of the AB 32 program with other environmental programs. (CSCME4)

> **Response:** This comment does not request any modifications. We appreciate the commenter’s support for this program.

J-17. Comment: Modify section 96013 as follows:

Penalties may be assessed pursuant to Health and Safety Code section 38580 for any violation of this article as specified in section 96014. In determining any penalty amount, ARB shall consider all relevant circumstances, including the criteria in Health and Safety Code section 42403(b), <u>and the degree of culpability for the violation</u>. (CCEEB3)

Response: We did not make the requested modification. Under Health and Safety Code section 42403(b), which is explicitly referenced in section 96013 of the modified cap-and-trade regulation, ARB must consider intent or its absence when seeking any penalty amount. As such, the requested modification is unnecessary.

Penalty of Perjury

J-18. Comment: Sections 95832(a) and (d) impose penalties of perjury on any Authorized Account Representative for any inaccurate statement. Subjecting these individuals to penalties of perjury under California law is an excessive individual burden for a person acting in his/her role as a company employee. These provisions should be deleted. (WPTF2)

Response: The responsibility placed on covered entities by the requirements of the cap-and-trade regulation includes submittal of complete and accurate information. We believe that the certification statements are a necessary component of ensuring that such information is true, complete, and accurate. Moreover, we note that such certification language is common in other regulatory programs, including the MRR and the U.S. EPA Greenhouse Gas Reporting Rule. Therefore, we did not delete the provision.

J-19. Comment: The proposed Regulation would require that designated representatives and certain others attest to the accuracy of filings made with ARB "under penalty of perjury of the laws of the State of California." PG&E recommends that this language be modified to certify the accuracy of filings "under penalty of law." ARB has provided no justification for its proposed requirement other than the circular reasoning that "addition [of the perjury language] is necessary to ensure that all information submitted is true and complete under penalty of perjury," and has not provided any information to show that inaccurate submittals are being made in other programs. The requirement to sign under penalty of perjury is unnecessary in light of provisions in the Health and Safety Code and elsewhere in these Regulations that penalize submission of inaccurate or incomplete information (see, Health and Safety Code subsection 42402.4; proposed regulations sections 95107 and 96014). Moreover, no stationary source air quality program PG&E is aware of, including the federal Clean Air Act Acid Rain program, Title V operating permit program, SCAQMD RECLAIM program, and numerous air district regulations, requires that submissions be made under penalty of perjury. (PGE4)

Response: The responsibility placed on covered entities by the requirements of the cap-and-trade regulation includes submittal of complete and accurate information. We believe that the certification statements are a necessary component of ensuring that such information is true, complete, and accurate. Moreover, we note that such certification language is common in other regulatory programs, including the MRR and the U.S. EPA Greenhouse Gas Reporting Rule.

Expand Penalties for Material Misstatement

J-20. Comment: PG&E appreciates ARB's recognition in section 95858 that penalties for unreported emissions should account for the five percent error margin specified in the definition of "material misstatement," and encourages ARB to extend that concept to the other enforcement sections. (PGE4)

Response: It is unclear from the comment in which manner the commenter is requesting the regulation be amended. We do appreciate the commenter's support for the modifications in section 95858.

Enforcement

Untimely Surrender/Excess Emissions

J-21. Comment: Modify section 96014 as follows:

(a) If an entity fails to surrender a sufficient number of compliance instruments to meet its compliance obligation as specified in sections 95856 or 95857, and the procedures in 95857(c) have been exhausted, there is a separate violation of this article for each 1000 required compliance instruments that ~~has~~ ~~have~~ not been surrendered, or otherwise obtained by the Executive Officer under 95857(c).
~~(b) There is a separate violation for each day or potion thereof after the end of the Untimely Surrender Period that each required compliance instrument has not been surrendered.~~
(~~c~~b) It is a violation to submit any record, information or repot required by this article that:

(1) Falsifies, conceals, or covers up by any trick, scheme or device a material fact;
(2) Makes any false, fictitious or fraudulent statement or representation;
(3) Makes or uses any false writing or document knowing the same to contain any false, fictitious or fraudulent statement or entry; or
(4) Omits material facts from a submittal or record.

(dc) The violations stated in section 96014(~~c~~b) are in addition to an entity's obligations under other provisions of this article requiring submissions to ARB to be true, accurate and complete. A submission may be considered a violation of section 96014(b) or of the obligations referenced in this section 96014(c), but not both. (CCEEB3)

Response: Regarding the commenter's requested modification to section 96014(b), we modified that provision to provide that, rather than having penalties for unsurrendered allowances accrue daily, penalties accrue every 45 days. This provides flexibility to the compliance entity to obtain additional allowances, either through an auction or by purchasing them through the allowance price containment reserve. It also reduces the potential liability for compliance entities. We did not make the requested modification to section 96014(d), which would unnecessarily limit ARB's ability to pursue enforcement actions, should we deem it necessary depending on all relevant circumstances.

J-22. Comment: Modify section 95857 as follows

~~(3) An entity's compliance obligation for untimely surrender may only be fulfilled with CA GHG allowances or allowances issued by a GHG ETS pursuant to subarticle 12; and~~

(~~4~~ 3) The untimely surrender obligation is due within five days of the first auction or reserve sale conducted by ARB following the applicable surrender date, whichever is the latter, and for which the registration deadline has not passed when the untimely surrender obligation is assessed. (CCEEB3)

Response: We modified section 95857 to reflect the intent similar to that proposed by the commenter. Covered entities can now use offsets and allowances to meet their untimely surrender as long as the entity does not violate the offset quantitative usage limit.

J-23. Comment: Section 96014(a) provides for a separate violation for each compliance instrument that is not surrendered. The basic penalty amount per violation under Health and Safety Code section 40402(b) is up to $10,000. At this amount, potential penalties when each ton is a violation are 200 to 1,000 times higher than expected allowance prices. There is no need for such extreme penalties, but the prospect of them has market impacts. Using each 1,000 instruments as way to limit the number of violations yields maximum penalties equivalent to expected allowance prices, and these are sufficient on top of the 4-1 excess surrender requirement in section 95857. Section 96014(a) contains a reference to section 95856, but that section is not relevant. If compliance instruments are not surrendered in accordance with section 95856, then section 95857(b) will apply, not section 96014. Section 96014 will apply only if compliance instruments remain outstanding under section 95857(c) (the "new untimely surrender obligation"). Section 96014(a) also contains some wording that SCPPA requested in response to an earlier version of the regulation—specifically referring to section 95857(c). This wording is no longer necessary as section 95857(c) has since been significantly amended. Modify section 96014(a) as follows :

(a) If an entity fails to surrender a sufficient number of compliance instruments to meet its compliance obligation as specified in section~~s~~ ~~95856 o~~r 95857, ~~and the procedures in 95857(c) have been exhausted,~~ there is a separate violation of this article for each 1,000 required compliance instruments, or portion thereof, that have~~s~~ not been surrendered~~, or otherwise obtained by the Executive Officer under 95857(c)~~. (SCPPA6)

Response: We did not bundle the allowances into 1,000 allowance units for purposes of determining penalties. One metric ton of CO_2e is the basic unit for both reporting under the MRR and for compliance or trading under the cap-and-trade regulation. It is therefore an appropriate unit by which to count violations under both rules. Moreover, Health and Safety Code section 38580(b)(3) authorizes ARB to define penalties on a per-unit basis, proportional to the conduct, rather than defining violations purely in terms of days. Moreover, we revised the penalty structure to provide that penalties for unsurrendered allowances accrue every 45 days, rather than having them accrue daily. This provides flexibility to the compliance entity to obtain additional allowances either through an auction or purchase of allowances through the allowance price containment reserve, and also reduces the potential liability for compliance entities.

J-24. Comment: Section 96014(b) should be amended. Instead of daily penalties, a 45-day period was included in section 96014(b) of the Discussion Draft. It is also referred to in the ARB's summary of the 15-day changes: "The section was also clarified to allow the violation to accrue every 45 days instead of each day the compliance instrument remained unsurrendered" (Page 41, section FFFF). The 45-day period should be included in the regulation to avoid unduly onerous penalties. In addition, section 96014(b) refers to the "Untimely Surrender Period." However, this term is not defined and is not used elsewhere in the regulation. This term should be replaced with a reference to the relevant section of the regulation. Also, there is no need for such extreme penalties. Using each 1,000 instruments as way to limit the number of violations yields maximum penalties equivalent to expected allowance prices, and these are sufficient on top of the 4-1 excess surrender requirement in section 95857. Modify section 96014(b) as follows:

(b) There is a separate violation for each 45-day period or portion thereof after the date determined pursuant to section 95857(b)(4)~~end of the Untimely Surrender Period~~ that each required 1,000 compliance instruments, or portion thereof, have~~s~~ not been surrendered. (SCPPA6)

Response: We modified section 96014(b) to provide that, rather than having penalties for unsurrendered allowances accrue daily, penalties accrue every 45 days. This provides flexibility to the compliance entity to obtain additional allowances, either through an auction or by purchasing allowances through the allowance price containment reserve. It also reduces the potential liability for compliance entities. However, we did not bundle the allowances into 1,000 allowance units for purposes of determining penalties. One metric ton of CO_2e is the basic unit for both reporting under the MRR and for compliance or trading under the cap-and-trade regulation. It is therefore an appropriate unit by which to count violations under both rules. Moreover, Health and Safety Code section 38580(b)(3) authorizes ARB to define penalties on a per-unit basis, proportional to the conduct, rather than defining violations purely in terms of days.

J-25. Comment: The Joint Utilities believe that provisions regarding consequences for non-performance should be both clear and concise, and should not be so onerous that an inadvertent or minor violation would result in the diversion of essential resources away from meeting the core goals of the Regulations. The Joint Utilities suggest that section 95857(c) be revised to further clarify that the untimely surrender obligation modifies the entity's original compliance obligation and does not create an additional obligation. The provisions of section 96014 should be changed in several respects, including a return to the 45-day period for accruing a violation as set forth in the July Discussion Draft and referenced in the Notice of 15-Day Revisions. Modify sections 95857(c) and 96014(a) and (b) as follows:

> 95857 (c) If an entity with an untimely surrender obligation fails to satisfy the obligation pursuant to section 95857(b)(4), then:
>
> > (1) ARB will determine the number of violations pursuant to section 96014;
> > (2) If a portion of the untimely surrender obligation is not surrendered as required, the entity will have a new untimely surrender obligation (replacing the previous surrender obligation calculated under section 95857(b)(2)) equal to the amount of the previous untimely surrender obligation which was not satisfied by the deadline stated in section 95857(b)(4) upon which the number of violations will be calculated pursuant to section 96014. The new untimely surrender obligation is due immediately; and
> > (3) The calculation of the untimely surrender obligation shall only apply once for each untimely surrender of compliance instruments per annual or triennial compliance obligation.
>
> 96014(a) If an entity fails to surrender a sufficient number of compliance instruments to meet its compliance obligation as specified in section~~s 95856 or~~ 95857, ~~and the procedures in 95857(c) have been exhausted,~~ there is a separate violation of this article for each 1,000 required compliance instruments, or portion thereof, that have~~s~~ not been surrendered~~, or otherwise obtained by the Executive Officer under 95857(c)~~.
> (b) There is a separate violation for each 45-day period or portion thereof after the date determined pursuant to section 95857(b)(4)~~end of the Untimely Surrender Period~~ that each required 1,000 compliance instruments, or portion thereof, have~~s~~ not been surrendered. (JOINTUTILITIES)

Response: We did not bundle the allowances into 1,000 allowance units for purposes of determining penalties. One metric ton of CO_2e is the basic unit for both reporting under the MRR and for compliance or trading under the cap-and-trade regulation. It is therefore an appropriate unit by which to count violations under both rules. Moreover, Health and Safety Code section 38580(b)(3) authorizes ARB to define penalties on a per-unit basis, proportional to the conduct, rather than defining violations purely in terms of days. Moreover, we revised the penalty structure to provide that penalties for unsurrendered allowances accrue every 45 days, rather than having them accrue daily. This provides flexibility to the compliance entity to obtain additional allowances, either through an auction or by purchasing them through the allowance price containment reserve. It also reduces the potential liability for compliance entities. It is ARB's intent that the "new obligation," as stated by the commenter, would replace the previous obligation.

J-26. Comment: Violations should be defined in units of 1,000 compliance instruments and 45-day period for additional violations should be re-included. Section 96014 describes the violation procedures for the Cap and Trade program, establishing the amount of violations that a regulated party may be subject to if insufficient compliance instruments are surrendered to cover the compliance obligation that remains after the untimely surrender obligation process. Several changes are beneficial in this section. First, SMUD believes that removing the reference to section 95856 here clarifies the basic violation as occurring only after untimely surrender has been dealt with, and renders moot the added language "… the procedures in 95857(c) have been exhausted…" The 15-day language states that when the requirements of section 95856 are not met, section 95857 is invoked, and it is only if the requirements of that section are not met that there is a violation. Section 96014 should clearly reflect this sequence for clarity. In addition, the term "Untimely Surrender Period" appears to refer back to section 95857(b)(4), but is not defined nor used elsewhere. It is best here to just refer to the date established by section 95857(b)(4). Second, SMUD continues to believe that with a basic penalty amount per violation under Health and Safety Code section 40402(b) of "up to $10,000", the potential penalties when each on is a violation remain egregious at 200 to 1000 times higher than expected allowance prices. There is no need for such extreme penalties, but the prospect of them has market impacts. Using each 1,000 instruments as way to limit the number of violations yields maximum penalties equivalent to expected allowance prices, and these are sufficient on top of the 4-1 excess surrender requirement established in section 95857. Third, section 96014(b) of the Discussion Draft of the Cap and Trade Regulation (released 07/07/11) included a reference to a 45-day period for violation accrual, rather than the daily accrual or multiplication that was proposed in the December 2010 Proposed Regulation Order. This 45-day period was also referred to in the ARB summary of the 15-day changes: "The section was also clarified to allow the violation to accrue every 45 days instead of each day the compliance instrument remained unsurrendered." (Page 41, section FFFF). It would appear that the intent was to continue to include the 45-day period in the 15-day language, and SMUD supports that inclusion. Modify section 96014 as follows:

(a) If an entity fails to surrender a sufficient number of compliance instruments to meet its compliance obligation as specified in sections ~~95856 or~~ 95857, ~~and the procedures in 95857(c) have been exhausted~~,there is a separate violation of this article for each <u>1,000</u> required compliance instrument<u>s, or portion thereof,</u> that ha<u>ve</u>~~s~~ not been surrendered, or otherwise obtained by the Executive Officer under 95857(c).

(b) There is a separate violation for each <u>45-</u>day <u>period</u> or portion thereof after the <u>date determined pursuant to section 95857(b)(4)</u>~~end of the Untimely~~

~~Surrender Period~~ that each required 1,000 compliance instruments, or portion thereof, haves~~s~~ not been surrendered. (SMUD3)

Response: We did not bundle the allowances into 1,000 allowance units for purposes of determining penalties. One metric ton of CO_2e is the basic unit for both reporting under the MRR and for compliance or trading under the cap-and-trade regulation. It is therefore an appropriate unit by which to count violations under both rules. Moreover, Health and Safety Code section 38580(b)(3) authorizes ARB to define penalties on a per-unit basis, proportional to the conduct, rather than defining violations purely in terms of days. Moreover, We revised the penalty structure to provide that penalties for unsurrendered allowances accrue every 45 days, rather than having them accrue daily. This provides flexibility to the compliance entity to obtain additional allowances, either through an auction or by purchasing them through the allowance price containment reserve. It also reduces the potential liability for compliance entities.

J-27. Comment: We support ARB's proposed amendments to section 96014(a) to specify that there is no violation for failure to surrender a sufficient quantity of compliance instruments unless the untimely surrender requirements of section 95857 are not met. However, we believe that a "per ton" penalty is inappropriately high, and should instead be one violation per 1000 tons, as suggested earlier. As written, section 96014(a) and (b) appear to impose penalties twice for the same shortfall in allowance surrender, except that the penalty in (b) is "per ton, per day." We suggest that ARB either delete (b), or clarify (b) to impose only a "per day" penalty for allowance surrender after the end of the untimely surrender period (with the "per 1000 tons") penalty applied once pursuant to (a). Section 96014(c) appears redundant and unnecessary, since the violations specified there would already be considered violations under the general obligations referenced in (d). We recommend that ARB either delete (c), or revise (d) to state that a submission may be considered a violation under (c) or under (d), but not both. Modify section 96014as follows:

(a) If an entity fails to surrender a sufficient number of compliance instruments to meet its compliance obligation as specified in sections 95856 or 95857, and the procedures in 95857(c) have been exhausted, there is a separate violation of this article for each 1000 required compliance ~~instrument~~instruments that ~~has~~have not been surrendered, or otherwise obtained by the Executive Officer under 95857(c).
~~(a) There is a separate violation for each day or portion thereof after the end of the Untimely Surrender Period that each required compliance instrument has not been surrendered.~~
(~~c~~b) It is a violation to submit any record, information or report required by this article that:

(1) Falsifies, conceals, or covers up by any trick, scheme or device a material fact;
(2) Makes any false, fictitious or fraudulent statement or representation;

(3) Makes or uses any false writing or document knowing the same to contain any false, fictitious or fraudulent statement or entry; or

(4) Omits material facts from a submittal or record.

(~~d~~c) The violations stated in section 96014(~~c~~b) are in addition to an entity's obligations under other provisions of this article requiring submissions to ARB to be true, accurate and complete. A submission may be considered a violation of section 96014(b) or of the obligations referenced in this section 96014(c), but not both. (PGE4, WSPA3)

Response: We did not bundle the allowances into 1,000 allowance units for purposes of determining penalties. One metric ton of CO_2e is the basic unit for both reporting under the MRR and for compliance or trading under the cap-and-trade regulation. It is therefore an appropriate unit by which to count violations under both rules. Moreover, Health and Safety Code section 38580(b)(3) authorizes ARB to define penalties on a per-unit basis, proportional to the conduct, rather than defining violations purely in terms of days. Moreover, we revised the penalty structure to provide that penalties for unsurrendered allowances accrue every 45 days, rather than having them accrue daily. This provides flexibility to the compliance entity to obtain additional allowances, either through an auction or by purchasing them through the allowance price containment reserve. It also reduces the potential liability for compliance entities. We did not make the requested modification to section 96014(d), which would unnecessarily limit ARB's ability to pursue enforcement actions, should we deem it necessary depending on all relevant circumstances.

J-28. Comment: Sections 95857 and 95858 discuss the enforcement provisions associated with the "Untimely Surrender of Compliance Instruments" and "Compliance Obligations for Under-Reporting." The relationship between these two provisions isn't well articulated in the Regulation. In addition, it appears that these provisions, along with the enforcement provisions under the Monitoring and Reporting Rule in section 95107(b) could result in double enforcement. Another concern is that while section 95858 provides for a notification from ARB when there has been under-reporting, there doesn't appear to be the same notification in section 95957. This is particularly of concern since section 95857(b)(l) appears to provide a short window to obtain the necessary additional allowances before a penalty of four times the missing allowances is required. (UNITEDAIRLINES2)

Response: We believe that the cross-references between sections 95857, 95858, and 96014 are sufficiently clear. Regarding the commenter's concern with layering of penalties between the MRR and the cap-and-trade regulation, we note that violations for under-reported tons and failures to measure in the manner required by the MRR will be dealt with solely under the MRR enforcement provisions. In terms of the cap-and-trade regulation, once a covered entity reports its emissions under the MRR, those emissions are then verified, and the covered entity receives either a positive, qualified positive, or adverse emissions verification statement. In the event of either a positive or qualified positive verification statement, the entity's cap-and-trade compliance obligation is equal to one allowance for each ton emitted. If a covered entity receives an adverse verification statement under the MRR, ARB will calculate and assign the covered entity's emissions level pursuant to section 95131(c)(5) of the MRR, and that level will become the covered entity's cap-and-trade compliance obligation. In either instance, if the covered entity is found (either in the current year or in a later year) to have under-reported its emissions, the penalty for the under-reporting will be wholly contained in the MRR—without the possibility of overlapping cap-and-trade penalties. On the other hand, failure to surrender sufficient compliance instruments, based on either an assigned emissions level or on a positive or qualified positive emissions level, will be subject to the penalty contained in the cap-and-trade regulation. Finally, we reiterate that the additional surrender obligation is not a penalty, per se. Rather, it is an additional incentive to ensure compliance with the regulation's surrender obligations.

Conflict Resolution

J-29. (multiple comments)
Comment: Currently, CARB's EO retains sole authority of program implementation of both the Cap and Trade and Mandatory Reporting Regulations, including determining whether regulated parties have complied with regulations and setting the penalties for such program violations. These important decisions will be made unilaterally without a public process and will have an impact on California businesses. It is important for these regulated entities to have a fair and transparent process by which to appeal a decision. CalChamber supports the adoption of a formal autonomous dispute resolution process that would enable facilities to challenge and resolve disagreements prior to potential enforcement actions through an equal process for all parties involved in any dispute. We believe this program should use an unbiased mechanism to resolve disputes, variances and penalty disagreements with the EO. Without a fair, independent process, an entity's options are limited. Currently, an entity's only recourse is to challenge the decision in court, which requires significant resources and time. Lawsuits are not only costly but rarely solve the underlying problem. We are proponents of a transparent process that helps reduce money and time spent defending lawsuits so that regulated entities can instead focus their time and efforts on job creation and economic stimulation. Without a fair and transparent dispute resolution process, issues that could be resolved relatively quickly could become time-consuming litigation that could hinder the goals of AB 32. (CALCHAMBER3)

Comment: Currently, the Cap and Trade and Mandatory Reporting Regulations give CARB's Executive Officer sole authority on program implementation, including determining whether regulated parties have complied with the Regulations and to determine penalties. Absent costly and time consuming litigation, there is currently no independent administrative option for stationary source facilities to challenge the Executive Officer's decisions that could not be resolved. CLFP believes the Executive Officer should not have the final decision on such a comprehensive program as AB 32, and instead it would be in both CARB's and the regulated industry's best interest that a formal, autonomous dispute resolution process should be established in order to provide independent decision making with equity for all parties involved in any dispute. This program should use an unbiased mechanism to resolve disputes, variances and penalty disagreements with the Executive Officer. Without such a program, issues that could be resolved relatively quickly could become time-consuming litigation which could hinder the goals of AB 32. (CALFP3)

Comment: Currently the cap-and-trade and mandatory reporting regulations give CARB's Executive Officer sole authority on program implementation, including determining whether regulated parties have complied with regulations and to determine penalties. The AB 32 IG believes the Executive Officer should not have the final decision on such a comprehensive program as AB 32, and instead it would be in both CARB's and the regulated industry's best interest that a formal, autonomous dispute resolution process should be established in order to provide independent decision making with equity for all parties involved in any dispute. This program should use an unbiased mechanism to resolve disputes, variances and penalty disagreements with the Executive Officer. (AB32IG2)

Comment: We strongly recommend that the Board direct staff to develop regulations for the operation of an independent administrative dispute resolution body. The sole purpose of this entity would be to adjudicate efficiently and fairly those factual, legal and jurisdictional disputes that inevitably will arise in the implementation of the AB 32 program. The absence of such an expert administrative dispute resolution body will not prevent controversy from arising. Indeed, in the absence of such an entity, aggrieved parties will simply take their disputes to courts of law. We strongly believe that an independent dispute resolution entity nested within the ARB can provide a fair and efficient means of adjudicating most disputes, thus assuring the smooth operation of the program and minimizing time delays, uncertainties and compliance costs. While there are a variety of disputes that could arise under the program, among the first will be disputes regarding actual emissions from covered entities (including staff decisions regarding "assigned emissions"). These may arise as the ARB staff attempts to apply different emission factors or missing data assumptions to covered entity operations. Another area of potential dispute may be whether offsets have properly been verified and, if so, what level of emission reductions they represent. There are innumerable situations under such a comprehensive regulatory program in which such factual, legal and jurisdiction disputes will arise. (CCC2)

Comment: Continue to work with stakeholder to provide a consistent mechanism to provide variances and resolve disputes. This Regulation and the other AB 32 regulations will apply to many facilities that have not previously been subject to ARB's regulations. These Regulations also provide significant discretionary authority to the Executive Officer. Shell is committed to our goal of full compliance with environmental regulations. However, we believe there will be situations where legitimate differences in interpretations and assessment of circumstances may require variances to address compliance issues that arise that are beyond the control of the entities or dispute resolution, which are best handled by an independent reviewer. Shell recognizes that

ARB currently disagrees with this position but requests that ARB continue to work with stakeholders to provide a consistent mechanism to resolve this issue. (SHELLOIL)

Response: The Executive Officer does not unilaterally "set" penalties. Health and Safety Code section 38580 provides ARB with enforcement authority over AB 32 regulations, including the authority to define the violations. This authority does not extend to assessing, imposing, or determining final penalty amounts. The governing statutes allow ARB to *seek* penalties in an administrative or judicial proceeding. In many of its enforcement actions, ARB and the entity from whom ARB is seeking penalties will reach a mutual settlement agreement, including an agreed upon penalty amount. ARB may seek penalties in an administrative or judicial action, in which the ultimate penalty amount is determined by a neutral judge, based on the statutory penalty structure. In no instance is ARB or its Executive Officer able to unilaterally assign a penalty amount on a violator.

Additionally, we note that the creation of a dispute resolution process is outside and beyond the scope of these regulatory amendments. Notwithstanding this, we disagree with the underlying premise of the commenter's suggestion; namely that there is no fair, independent, autonomous method of resolving these disputes. As the commenter acknowledges, the existing recourse is to challenge a decision in court. That process is well established and understood by regulated entities, the public, and ARB. Inventing a new, additional dispute resolution process, whether that would be through the creation of a hearing board or an administrative hearing, will not necessarily reduce the time or expense of resolving such disputes. In fact, and contrary to the claimed rationale of the commenter, ARB believes such additional process may actually increase the time and expense of resolving these matters, since parties could still ultimately end up back in court. Including an additional dispute resolution process would give rise to delay that could have broad market impacts. As such, ARB does not agree that including such a process would be appropriate.

Regarding variances, we do not believe the "variance" process used by the local air districts is necessary for the MRR or cap-and-trade regulations, and believe that it could disrupt the market features of the cap-and-trade regulation, which relies on the emissions data reports from the MRR. Unlike the future emissions addressed by local air district variance processes, the emissions at issue in the MRR and the cap-and-trade program have already occurred and been reported to ARB. As such, no "variance" is required, and as such, the formal variance process used by the air districts would be inappropriate for the MRR. In addition, instead of a formal variance process, the MRR includes a process by which a facility may petition for an interim data collection method under certain circumstances that would otherwise result in loss of data for unforeseen reasons. The MRR also contains a petition process for when a reporting entity and its verifier do not agree on the quality of the emissions data report.

ARB Jurisdiction

J-30. Comment: We strongly recommend that ARB retain the ability to enforce against negligent actions, and strict liability for errors and omissions, etc. While we agree that severe penalties should apply to knowing and intentional violations, intent can be very difficult to establish, and it is important for the integrity of the program that lesser violations be subject to enforcement action, and penalty amounts up to the limits prescribed in the Health and Safety Code. ARB always retains the ability to use its enforcement discretion, should it feel that the facts do not warrant those penalty levels. (CAPCOA2)

> **Response:** While the comment does not refer to any specific modifications to the cap-and-trade regulation, we appreciate and agree with the commenter's recommendation. Existing statutes provide for different penalties based on different mental states; namely, strict liability, negligence, knowledge, and intent.

J-31. Comment: In all places where the rules refer to the enforcement authority of the State of California, or to the authority of the Executive Officer of the ARB, it should be noted that such authority is conferred on any agent officially designated or recognized as having such authority, or authorized by law to enforce these rules. (CAPCOA2)

> **Response:** ARB believes that it has drafted the enforcement provisions consistently with the authority granted to us by AB 32. As such, we did not make the requested change.

J-32. Comment: Under proposed modified section 95921, ARB creates rules relating to the conduct of trading in compliance instruments. In effect, ARB grants the Executive Officer the ability to reverse transactions that violate, in part, holding limits specified in section 95920. We understand the need for ARB to develop an enforcement mechanism for these rules. However, IETA is concerned that the mechanism outlined in section 95921 provides ARB an unprecedented enforcement power, which ultimately could be detrimental to trading liquidity and the ability for entities to hedge price risk and comply with carbon reduction targets at the lowest possible cost. Reversing commercial transactions between counterparties creates a host of contractual and compliance issues. A fundamental tenet of a properly functioning market is that commercial contracts between counterparties cannot be unwound. An obligation to sell allowances to another counterparty must be met, and once the transfer of allowances and cash has taken place counterparties cannot be expected to reverse this transaction. To create the possibility of a transaction reversal would introduce an unacceptable measure of risk to carbon transactions. Sellers would be exposed to undue price risk in the interim between the transaction and the transfer, and a reversal might present market risk that impedes implementation of hedging strategies. Furthermore, such reversals may create a daisy chain of violations of holding limit provisions. In the instance of ARB reversing a transaction, the buyer of allowances will return the allowances to the seller. The seller may have sold the allowances to ensure it did not violate its own holding limits, and the return of allowances from the reversed transaction might then put the seller over its holding limit. This would, in turn, generate another series of reversals that would impact still other counterparties. Importantly, a seller will have no insight into the holdings of the buyer, and therefore should not be responsible for returning cash to the buyer and taking back allowances in instances where the seller is over the proposed holding limit. IETA, instead, suggests ARB consider enforcement provisions for Holding Limits in which the responsibility rests solely on the entity in violation of these provisions. IETA encourages ARB to consider such enforcement that does use market transactions (or reversal thereof) as the mechanism for compliance. (IETA3)

> **Response:** The essence of the regulation is that ARB's approval is required before a contract can be fully executed, i.e., the owner of the allowance does not have the ability to transfer allowances. In effect, the contract is not approved until ARB is satisfied that the transfer meets all of the regulation’s requirements, thus there is no reversing of commercial transactions contemplated by the regulation. ARB has no interest in upsetting the commercial market by unwinding completed contracts (where there has been no fraud on the regulatory regime), and it requires complete transparency of allowance movement via the regulations. The comment raises an example for the necessity of the regulation: the seller cannot know whether the holding limits would be violated by a proposed contract. The regulation provides ARB with notice of all allowance transactions before they are completed, so that the holding limit can be enforced. The comment proposes after-transaction attempts to enforce its regulations—prevention of violations is preferable both for the market and the regulator.

Jurisdiction of California

J-33. Comment: Section 96022 is duplicative to Section 96010. The Utilities recommend deleting this section all together since jurisdiction is fully covered in greater detail in section 96010. Modify section 96022 as follows:

> ~~Any party that participates in the Cap and Trade Program is subject to the jurisdiction of the State of California~~. (MID3)

> **Response:** We understand the commenter’s concern, and we will continue to discuss this issue with stakeholders and propose any changes as needed.

J-34. Comment: Section 90622 has been modified to attempt to ensure that all program participants are subject to the jurisdiction of California. Similar language is included in a number of places where the participant is required to certify that he or she consents to that jurisdiction. We suggest that the language in section 96022 and other certification sections be broadened to ensure that participants are subject to (1) service of process in California (by requiring them to designate a registered agent for service of process); (2) choice of law (i.e. disputes will be governed by California law); and (3) jurisdiction and venue in California (may prefer that for out-of-state participants, venue will be in Sacramento). Language accomplishing these three purposes is contained in SCAQMD's RECLAIM Rule, which may be adapted for this purpose. Please see

SCAQMD Rule 2007(e)(2)(J) for example. (SCAQMD4)

Response: We do not believe that the requirements stated by the commenter are appropriate at this time. Sections 96022 and 96010 both require that any entity participating in the cap-and-trade program submit to the jurisdiction of California. If obtaining service of process becomes problematic, we are prepared to amend the regulation at a later time.

J-35. Comment: Certifications currently state, "I certify under penalty of perjury under the laws of the State of California… is true, accurate, and complete." To be consistent with certifications made under the CAA for other programs, the language should be modified to state, "I certify under penalty of perjury under the laws of the State of California… is, to the best of my knowledge, true, accurate, and complete." (VALERO2)

Response: We understand the commenters concern, and we will continue to discuss this issue with stakeholders and propose any changes as needed.

Miscellaneous

J-36. Comment: It is critical that ARB's decision to begin enforcement in 2013 not lead to any delay in the launch or operation of the program. (KUSTIN16)

Response: The comment does not request any modifications. However, we do not believe the decision to begin enforcement in 2013 will lead to any delay in the launch or operation of the program.

J-37. Comment: The Utilities support the clarification of the penalty amount determination provided for in Subarticle 15. Unfortunately, the Utilities continue to have concerns with the way violations are calculated in section 96014. (MID3)

Response: The comment does not request any modifications. We responded to specific concerns and requested modifications throughout the other responses to comments related to the enforcement provisions.

Support

J-38. Comment: We support and appreciate ARB's revision of section 96014, which specifies what constitutes a violation under the rule and triggers the penalty provisions in the Health and Safety Code. The previous iteration of the rule left some ambiguity on what conduct, short of a covered entity failing to meet its compliance obligation, constituted a "violation" and thereby authorized ARB to pursue administrative penalties as an enforcement mechanism. ARB's retooled approach in section 96014(c) eliminates any uncertainty and will help encourage compliance from all entities who participate in every aspect of the program. (KUSTIN16)

Response: The comment does not request any modifications. We appreciate the commenter's support for this program.

J-39. Comment: EDF supports the proposed improvements to the regulatory enforcement and oversight provisions. These expanded provisions in the 15-day change document create significant new safeguards by ensuring that CARB has enough information at its disposal to pursue violations with civil penalties, seek out additional reductions (replacement credits) as needed, and ensure the regulation works without fraud or manipulation. With the incorporation of a regimented enforcement tracking system and market manipulation oversight board, CARB and its appointed officers will have enough information to be able to detect and ameliorate fraudulent transactions that may occur within the credit trading market prior to credits being surrendered for compliance. Such provisions also serve as a strong deterrent to fraud and malfeasance. EDF strongly supports these proposed improvements. (EDF4)

Response: The comment does not request any modifications. We appreciate the commenter's support for this program.

J-40. Comment: As revised below, we support ARB's proposed amendments to reference violations as specified in section 96014 and to reference the statutory penalty factors specified in Health and Safety Code Section 42403(b):

(b) Penalties may be assessed pursuant to Health and Safety Code section 38580 for any violation of this article as specified in section 96014. In determining any penalty amount, ARB shall consider all relevant circumstances, including the criteria in Health and Safety Code Section 42403(b)<u>, and the degree of culpability for the violation.</u> (PGE4, WSPA3)

Response: We did not make the requested modification. Under Health and Safety Code section 42403(b), which is explicitly referenced in section 96013 of the modified cap-and-trade regulation, ARB must consider intent or its absence when seeking any penalty amount. As such, the requested modification is unnecessary.

K. LEGAL

Authority to Raise Revenue

K-1. Comment: Some question has arisen about the legality of section 95892(a) with regard to CARB's ability to issue guidance or regulation on how allowance proceeds can or should be used. Although EDF leaves that answer to the agency and the legislature, we observe that the text of AB 32 supports the Regulation's current language, wherein under AB 32 CARB shall "adopt regulations governing how market-based compliance mechanisms may be used by regulated entities subject to greenhouse gas emission limits … to achieve compliance with their greenhouse gas emissions limits." (EDF4)

> **Response:** We thank the commenter for the support of ARB's regulations.

Comment Period

K-2. Comment: NAIMA's comments have been largely ignored. The public comment process seems to have been a mere formality without any of the extensive dialogue and exchange of information between NAIMA and CARB resulting in modifications to CARB's regulatory proposal that accommodates manufacturers struggling to do business in California. (NAIMA2)

> **Response:** We did receive and review the comments submitted by NAIMA. We held over 40 workshops during the development of this regulation and provided many opportunities for stakeholders to provide input. The specific topics within those comments are being addressed as part of the Final Statement of Reasons within the respective subject matter areas.

General

K-3. Comment: We have not seen any response to our prior December 13, 2010, comment on the fatal flaws of the greenhouse gas offset program and protocols, or our July 30 and August 1, 2008, comments on the flaws of Cap and Trade with offsets as an approach to addressing greenhouse gases. Not only did CARB fail to respond in writing to our comments, but CARB also failed to respond in writing to other commenters who described the flaws of offsets and their potential to undermine the integrity of the AB 32 program. The San Francisco Superior Court decision dated March 18, 2011, states that CARB is required to respond to comments prior to making a decision. We do not believe it is legal for CARB to move forward with adopting or approving the offset program and/or protocols until our comments have been presented to the Board and responded to in writing. See Superior Court Decision at p.33, citing California Code of Regulations, Title 17, section 60007(a). (WILLIAMSZ2)

> **Response:** The Administrative Procedure Act (APA) requires ARB to respond to all written comments received during any open comment periods in the Final

Statement of Reasons. However, it is not required by the APA that these responses be sent to the commenter making the comment, nor is it required that the responses be completed at the time of the Board hearing. ARB is required to respond to comments related to its CEQA analysis (Appendix O of the Initial Statement of Reasons) prior to adoption of the regulation. ARB circulated the *Response to Comments on the Functional Equivalent Document Prepared for the California Cap on GHG Emissions and Market-Based Compliance Mechanisms* prior to the Board's hearing on October 20, 2011, and considered those responses prior to adopting the regulation. The court order cited by the commenter is stayed pending appeal.

Dispute Resolution Process

K-4. Comment: CCEEB recommends that ARB establish an independent administrative dispute resolution process that will provide a fair, efficient, and predictable process available to all individual facilities. This will reduce the money and time spent defending lawsuits and in informal negotiations. It will also increase the transparency of the appeal process as all interested stakeholders can weigh-in during a hearing. The proposed dispute resolution process could be modeled after existing air pollution hearing processes for disputes at individual facilities that occur under local air district rules. (CCEEB3)

Response: As noted previously in responses to 45-day comments, ARB did not implement this recommendation. Whether a covered entity surrenders sufficient allowances is not a question that lends itself to an administrative dispute resolution.

Does Not Meet AB 32 Requirements

K-5. Comment: The proposed program and protocols do not meet the requirements for greenhouse gas offsets in AB 32. The proposed regulation provides admissions of uncertainty and unenforceability. For example, the statement at page 9, (35) "Business-as-Usual Scenario" means the set of conditions reasonably expected to occur within the offsets project boundary in the absence of the financial incentives provided by offset credits, taking into account all current laws and regulations, as well as current economic and technological trends. "Reasonably expected to occur" in this context is speculative and subjective and cannot be part of an enforceable standard." In addition, offset credits are to be provided for many activities that have already occurred as part of "early action." Further, actions that are admittedly part of business as usual, such as activities that are "significantly better than average" are defined as "additional" for purposes of the offset protocols. (See Staff Reports for three of the proposed Offset Protocols dated October 28, 2010; page 5 of the Manure Digesters Protocol, p.6 of Ozone Depleting Substances, p. 5 Urban Forests Protocol). These flaws and others discussed in our December 13, 2010, comment will be a system that claims reductions based on activities that cannot be verified to be additional to what would have happened in the absence of the offset payments. This in turn will result in false accounting and a false sense of security that the problem is being successfully addressed. The program will also fail to correct the incentives that keep greenhouse gas emissions at dangerous, unsustainable levels, thereby locking in additional climate degradation. Therefore, offsets should not be part of the AB 32 program to reduce greenhouse gas emissions. (WILLIAMSZ2)

> **Response:** This comment does not address proposed 15-day changes to the regulation. Furthermore, as each offset protocol is developed, we will set conditions and criteria that ensure that the resulting offset credits meet the AB 32 criteria through conservative and well-quantified methods.

K-6. Comment: Did CARB determine that the proposed regulation's treatment of DWR and its water customers is equitable as required by AB 32? If so, what is the basis for that determination? (DWR2)

> **Response:** AB 32 requires that GHG reductions be achieved through cost-effective methods for the largest GHG emitters for the State of California. By implementing a market-based program, certain commodities will have a carbon price to incent changes in behavior to reduce the associated GHG emissions. DWR is provided equal treatment under the program as other sectors that provide goods, with similar potential leakage, and ability for cost pass-through to end users. To that extent, the DWR customers are treated equitably as customers of any other products from sectors with similar leakage and cost pass-through circumstances.

K-7. Comment: Did CARB determine that the proposed regulation's treatment of DWR and its water customers will achieve reductions in greenhouse gas emissions that are real, permanent and quantifiable, as required by AB 32? If so, what is the basis for that determination? (DWR2)

> **Response:** These specific criteria apply to GHG reductions used for compliance from voluntary action such as offsets. The rigorous reporting and verification requirements for DWR will ensure that any changes in emissions are quantifiable and real.

K-8. Comment: Did CARB determine that the proposed regulation's treatment of DWR and its water customers is a cost-effective method for achieving greenhouse gas emissions reduction, as required by AB 32? If so, what is the basis for that determination? (DWR2)

> **Response:** All regulations developed by ARB must undergo a cost analysis with findings published in the Staff Report. Furthermore, the Scoping Plan FED identified a cap-and-trade program as the best strategy to meet the AB 32 GHG emissions reduction targets in a cost-effective manner.

K-9. Comment: The proposed 15-day modifications negatively impact California's economy. The modifications do not remedy the Regulation's failure to capitalize on the opportunity to create well-paying green jobs in California and fuel a green economic revolution. The Regulation forgoes the economic and public health benefits from in-state reductions, favors out-of-state reductions from virtually unlimited offsets, and creates a vastly complicated and unproven mechanism—cap and trade—that will likely fail to deliver on AB 32 ultimate goal of reducing GHG emissions in a thoughtful and equitable manner by 2020. Questions about the efficacy, fairness, and economic soundness of this Cap and Trade Regulation have been posed by various organizations, including the Legislature, and the modifications do not address any of these questions. (CRPE4)

> **Response:** This comment does not address proposed 15-day changes to the regulation; rather, it reiterates comments made during the initial 45-day comment period. No response is required. However, we have addressed all public comments as part of this FSOR.

K-10. Comment: ARB should halt development and implementation of this modified Cap and Trade Regulation until questions about the appropriateness of a cap and trade system to meet all the requirements of AB 32 can be answered. (CRPE4)

> **Response:** This comment does not address proposed 15-day changes to the regulation; rather, it reiterates comments made during the initial 45-day comment period. No response is required. We believe the cap-and-trade program is designed to meet all of the requirements under AB 32 to help California reach its GHG emission reduction targets.

K-11. Comment: The modified regulation continues to fail to achieve maximum environmental and economic benefits for California, as required by AB 32. Under the modifications, compliance with the program doesn't begin until 2013. Since the "cap" begins at a business as usual amount, there are no reductions required that year. Offsets and free allowances provide no economic benefits for California. Under the Regulation, entities can use out of state offsets to meet their emission reduction requirements. This sends green jobs, and the environmental benefit of the reductions, out of the state of California. In addition, agricultural emissions, a major greenhouse gas contributor, are still not regulated. Nothing in the modifications changes these fundamental flaws in the Regulation. (CRPE4)

> **Response:** The cap-and-trade regulation is one of several strategies designed to achieve AB 32 mandates. Taken together, these strategies do achieve the environmental and economic benefits for California as required under AB 32. This comment does not address 15-day changes to the regulation; rather it reiterates comments made during the initial 45-day comment period. No further response is required.

Environmental Justice

K-12. Comment: The proposed 15-day modifications do not remedy the regulation's violation of AB 32 to avoid disproportionate impacts on low-income communities and communities of color. ARB's quest to reduce greenhouse gas (GHG) emissions and to build upon California's tradition of environmental leadership both nationally and internationally should not come at the expense of these communities. The Regulation continues to accept and promote the disparate and discriminatory treatment of the most vulnerable communities in our State. (CRPE4)

> **Response:** This comment does not address proposed 15-day changes to the regulation; rather, it reiterates comments made during the initial comment period. No response is required. However, we maintain the regulation is non-discriminatory and does not promote disparate treatment of any population in the State.

Consideration of Alternatives

K-13. Comment: ARB continues along two irreconcilable tracts by working on the Supplemental Functional Equivalent Document for alternatives to the Scoping Plan while also continuing to develop and modify the Cap and Trade Regulation. It is impossible to perform a meaningful and good-faith alternatives analysis that will inform the Board's decision making, when ARB simultaneously develops and implements the very plan for which it is supposedly reviewing alternatives. This basic fact, which seems to escape ARB, is obvious to the Superior Court, the Legislative Analyst's Office (LAO), and the public. The LAO recommended that the Legislature direct ARB to halt work on the Regulation until ARB completed and presented to the Legislature an analysis of alternatives to Cap and Trade. Continuing to develop this Regulation while, at the same time, claiming to analyze potential alternatives is disingenuous. ARB should not continue modifying and developing this Regulation until it performs a good faith and meaningful analysis of alternatives. Given that the modifications seek to push the compliance obligation back to 2013, ARB has no excuse as to why it can't stop and review alternatives that will get better reductions, enhance California's economy, and fairly reduce greenhouse gases and co-pollutants across all California communities. (CRPE4)

> **Response:** This comment does not address proposed 15-day changes to the regulation; rather, it reiterates comments made during the initial 45-day comment period. ARB has performed a meaningful and good faith analysis of alternatives to the Scoping Plan, while continuing its work on the development of the proposed cap-and-trade regulation. At the August 24, 2011, Board hearing, the Board reviewed ARB's Supplement to the FED for the Scoping Plan, which provided an expanded analysis of alternatives. After reviewing the Supplement and the public comment on the Supplement and responses to those comments, the Board determined that the Proposed Scoping Plan presented the best alternative.

In relation to the pending litigation, ARB applied for and the Court of Appeal granted a stay of the Superior Court order the commenter references. Further, the California Supreme Court has since denied a petition to review the Court of Appeal's stay.

Finally, the Board considered the 15-day changes to the proposed cap-and-trade regulation, as well as the comments on the Cap-and-Trade FED (Appendix O) and ARB's responses to those comments, and approved the cap-and-trade regulation at its meeting on October 20, 2011.

K-14. Comment: ARB should not continue to develop, modify, or implement the Cap and Trade Regulation. The undersigned organizations ask ARB to halt all work on the Regulation until a meaningful alternatives analysis can to be done and the Board can decide whether Cap and Trade is the best way to achieve maximum reductions, while boosting California's green economy and being mindful of California's already over-burdened communities. If ARB refuses to discontinue developing the Cap and Trade Regulation, then it must recirculate the FED and have the final language of the Regulation go back to the Board for review, response to comments, and final decision. (CRPE4)

Response: See the previous response.

Violates CEQA

K-15. Comment: ARB's process violates CEQA. On December 16, 2010, the Board passed Resolution 10-42 to approve the Cap and Trade Regulation. The Board did not respond to public comment before it approved and instead directed the Executive Officer to evaluate and prepare responses. While final adoption is delegated to the Executive Officer, the Board has approved the Regulation without seeing the final "adopted" Regulation unless the Executive Officer determines it is warranted. Since the Board's adoption in December 2010, there have been five workshops to discuss various components of the Cap and Trade Regulation. The current modifications are supposed to address some of the public's concerns voiced during these workshops, and include modifications adopted in the December Resolution. The Resolution allows the Executive Officer to modify the Regulation that was before the Board in December 2010 within his discretion, without limits, and without requiring the Board to review the final regulation before it is approved. The Executive Officer, who is not a public official, reviews and responds to public comments on the modifications and determines whether the Regulation should be presented to the Board for further consideration. Given the complexity and the enormous impact and reach of the modified rule, the Board, not the Executive Officer, must review, respond to comments, and make a final decision. Thus, the Board has not completed its required environmental review before approving the project. This process violates CEQA. (CRPE4)

Response: Board Resolution 10-42 directed staff to finalize the cap-and-trade regulation. The resolution specifically indicates on page 10 that the regulation is not approved, and that the Executive Officer may bring the regulation back to the Board for its approval. The Board approved the regulation at its meeting on October 20, 2011.

Auction

Allowance Price

K-16. Comment: Section 95921(d) delineates the release and protection of transaction price and quantity information. WSPA believes that release individual transaction price and quantity information does not provide adequate confidentiality protection. WSPA recommends that this section be amended to require release of transaction price and quantity in an aggregated format for confidentiality protection. (WSPA3)

Response: Section 95921(d) does not indicate that individual transaction prices will be released. What data will be released and when is a question of implementation. ARB appreciates the complexity of protecting confidential business information and its relationship to the integrity of the allowance market.

Authority to Regulate

K-17. Comment: CSCME is pleased that CARB recognizes that a public notice and comment period would be required prior to implementation of any command-and-control measures requiring that firms take certain actions identified as cost-effective in each individual firm's Energy Efficiency and Co-Benefits Audit ("EEA"). CARB should not implement new command-and-control measures on top of existing cap-and-trade measure. CARB lacks legal authority to implement such a command-and-control provision to regulate emissions other than greenhouse gas ("GHG") emissions under AB 32. By utilizing the proposed command-and-control approach to require all cost-effective actions identified in EEAs, CARB would exceed its legislative delegation under AB 32 to regulate solely GHG emissions. In addition to GHG emissions, EEAs will consider criteria air pollutants and toxic air contaminant emissions. Although the legislature could have given authority to CARB to regulate other emissions under AB 32, it did not do so. Thus, CARB would exceed its authority by considering criteria pollutants in determining which measures are cost-effective. (CSCME4)

Response: This comment is not directed at changes to the cap-and-trade regulation, rather it is directed to the potential outcome of ARB's Energy Efficiency and Co-Benefits Audit and the relationship between that regulation and the cap-and-trade regulation. Any additional changes to either regulation (or any new regulation) would be subject to a new public process under the Administrative Procedure Act.

K-18. Comment: Western, a federal agency, continues to express concerns that CARB's regulations include Western as a regulated entity. The Supremacy Clause of the United States Constitution does not allow a state to directly regulate the federal government without its consent or within a field regulated entirely by the federal government. Western understands CARB believes the Clean Air Act provides a waiver of sovereign immunity for these regulations. While Section 118 of the Clean Air Act, 42 U.S.C. section 7418, provides a limited waiver of sovereign immunity and under certain circumstances requires federal facilities to comply with federal, state, interstate and local requirements for the abatement of air pollution to the same extent as any nongovernmental entity, under the Act, there must be an action by the United States to delegate authority over cap and trade for greenhouse gases to the state before a federal agency may comply with state regulations. As of this writing, neither the U.S. Congress nor the EPA has promulgated any such cap and trade laws or regulations. There is no waiver of sovereign immunity and Western does not have authority to bind Congress, EPA or other federal agencies with jurisdiction over such matters. Furthermore, these regulations directly impact Western's primary mission of marketing federal power, a field regulated entirely by the federal government. Therefore, Western continues to believe the regulations should not include Western as a regulated party. Western will continue to work with the state and may voluntarily participate in cap and trade. However, at this time, Western cannot consent to direct state regulation. Modify section 95802(a)(246) as follows:

> (246) "Retail Provider" means an entity that provides electricity to retail end users in California and is an electric corporation as defined in Public Utilities Code section 218, electric service provider as defined in Public Utilities Code section 218.3, local publicly owned electric utility as defined in Public Utilities Code section 224.3, a community choice aggregator as defined in Public Utilities Code section 331.1~~, or the Western Area Power Administration~~. For purposes of this article, electrical cooperatives, as defined by Public Utilities Code section 2776, are excluded.

(or)

> (246) "Retail Provider" means an entity that provides electricity to retail end users in California and is an electric corporation as defined in Public Utilities Code section 218, electric service provider as defined in Public Utilities Code section 218.3, local publicly owned electric utility as defined in Public Utilities Code section 224.3, a community choice aggregator as defined in Public Utilities Code section 331.1, ~~or the Western Area Power Administration~~. <u>Federal agencies, including Western Area Power Administration (WAPA) may voluntarily participate under these regulations.</u> For purposes of this article, electrical cooperatives, as defined by Public Utilities Code section 2776, are excluded. (WAPA2)

> **Response:** This comment does not address the 15-day changes to the regulation and restates the commenter's already expressed belief that it is not subject to the regulation because it is a federal agency. ARB continues to disagree with that assertion. Please refer to responses to Comments K-8 and K-9 in the 45-day responses.

K-19. Comment: BPA strongly disagrees with ARB that it has “authority” to regulate BPA and that BPA is “required” to comply. BPA wishes to make clear that BPA is participating in California’s GHG reporting program and cap and trade program purely on a voluntary basis. BPA is not conceding that California has any jurisdiction over BPA. Sovereign immunity may prevent BPA (and similarly WAPA) from being subject to these regulations. Despite ARB’s position that the Clean Air Act waives sovereign immunity, it is questionable whether that waiver would cover BPA because it is purely a marketer that is not engaged in an activity that discharges pollutants. Although BPA intends to voluntarily comply with these regulations, BPA is concerned that mandatory regulations could interfere with its existing contracts and conflict with the marketing scheme established by Congress in BPA’s governing statutes. Moreover, because BPA is willing to voluntarily comply, it is not necessary for ARB to include these jurisdictional assertions in its rules. Doing so could unnecessarily raise complicated legal issues that are unnecessary to fully and timely implementation of the greenhouse gas reporting rules and/or the cap and trade program. Modify section 95802(a)(84) as follows:

> (84) “Electricity importers” are marketers and retail providers that hold title to imported electricity. For electricity delivered between balancing authority areas, the entity that holds title to delivered electricity is identified on the NERC E-tag as the purchasing-selling entity (PSE) on the tag’s physical path, with the point of receipt located outside the state of California, and the point of delivery located inside the state of California. ~~Federal and s~~<u>S</u>tate agencies are subject to the regulatory authority of ARB under this article and include ~~Western Area Power Administration (WAPA), Bonneville Power Administration (BPA), and~~ California Department of Water and Power (DWR). When PSEs are not subject to the regulatory authority of ARB, including tribal nations, the electricity importer is the immediate downstream purchaser or recipient that is subject to the regulatory authority of ARB.

(or)

> (84) “Electricity importers” are marketers and retail providers that hold title to imported electricity. For electricity delivered between balancing authority areas, the entity that holds title to delivered electricity is identified on the NERC E-tag as the purchasing-selling entity (PSE) on the tag’s physical path, with the point of receipt located outside the state of California, and the point of delivery located inside the state of California. ~~Federal and s~~<u>S</u>tate agencies are subject to the regulatory authority of ARB under this article and include ~~Western Area Power Administration (WAPA), Bonneville Power Administration (BPA), and~~ California Department of Water and Power (DWR). <u>Federal agencies, including Western Area Power Administration (WAPA) and Bonneville Power Administration (BPA), may voluntarily participate under these regulations.</u> When PSEs are not subject to the regulatory authority of ARB, including tribal nations, the electricity importer is the immediate downstream purchaser or recipient that is subject to the regulatory authority of ARB. (BONNEVILLEPWR2, WAPA2)

Response: This comment does not address changes to the regulation and restates the commenter's already expressed belief that it is not subject to the regulation because it is a federal agency. ARB continues to disagree with that assertion. Please refer to responses to Comments K-8 and K-9 in the 45 day responses.

Tribes: Various Topics

K-20. Comment: Modify section 95975(l)(1). California Government Code Section 825(a) states "Nothing in this section authorizes a public entity to pay that part of a claim or judgment that is for punitive or exemplary damages." There are similar provisions to protect the federal government and the State of California. It would be discriminatory to only have punitive damages for Indian Tribes. The Tribe's proposed substitute language under this section adequately allows ARB to seek the remedies which are necessary to robustly enforce your regulations. Modify section 95975 (l)(1) as follows:

(1) The governing body of the Tribe must enter into a limited waiver of sovereign immunity with ARB related to its participation in the requirements of the Cap-and-Trade Program for the duration required by the applicable Compliance Offset Protocol(s). This waiver must include a consent to suit by ARB and the State of California, in the courts of the State of California, with respect to any action in law or equity commenced by ARB or the State of California to enforce the obligations of the Tribe with respect to its participation in the requirements of the Cap-and-Trade Program for the duration required by the applicable Compliance offset Protocol(s). This waiver must include a consent to suit by ARB and the State of California, in the courts of California, with respect to any action in law or equity commenced by ARB or the State of California to enforce the obligations of the Tribe with respect to its participation in the Cap-and-Trade Program,~~irrespective of the form of relief sought, whether monetary or otherwise.~~ <u>with such forms of relief, whether monetary or otherwise, which are acceptable to the ARB.</u> (YUROKTRIBE)

Response: California Government Code Section 825(a) applies specifically to instances in which a public entity conducts the defense of an employee or former employee for an injury that arose out of an act or omission occurring within the scope of his or her employment as an employee of the public entity. The commenter has not specified how this Government Code section is applicable to the offset projects contemplated in the Cap-and-Trade Regulation. We disagree that the specific language change requested by the commenter would address the concern, believe it is overly vague, and did not make the requested change. ARB notes that the cap-and-trade regulation is designed to ensure equitable treatment, to the greatest extent possible, of all offset project operators and all offset projects, whether on public or private land. We will, consistent with the design of the program, not discriminate against Tribes or other government entities and will treat all projects equitably.

K-21. Comment: The Solicitor of the Department of the Interior has not provided a formal opinion on the subject of federal approval of carbon sales on tribal lands. Modify section 95975(l)(3) as follows:

(1) For offset projects located on Indian lands, as defined in 25 U.S.C. section 81(a)(1), the Tribe must also provide ARB with proof of federal approval, <u>or proof that federal approval is not required</u>, of the Tribe's participation in the requirements of the Cap-and-Trade Program. (YUROKTRIBE)

Response: We agree with the commenter that federal approval may not be required for a Tribe's participation in the cap-and-trade program in all instances, and included modified regulatory language to specifically address the commenter's concern. This language will allow Tribes to provide either proof of federal approval or documentation that federal approval is not required.

K-22. Comment: Section 95975(l)(3) may be drafted too broadly. There is no consensus about the situations in which federal government (BIA) approval may be necessary for projects located on Indian lands, and in many circumstances the BIA may not yet have a policy formulated for whether approval is necessary. In essence, the question here is whether the project activity has been properly permitted. We urge ARB to treat this like any other governmental permit by simply requiring it "if applicable" and accept it in the form suitable to the permitting agency. Modify section 95975(l)(3) as follows:

(2) For offset projects located on Indian lands, as defined in 25 U.S.C. section 81(a)(1), <u>if necessary under applicable law and policy</u>, the Tribe must also provide ARB with proof of federal approval of the Tribe's participation in the requirements of the Cap-and-Trade Program, <u>in a form provided by the approving federal agency</u>. (NEWFOREST2)

Response: See the response to Comment K-21.

K-23. Comment: There is concern about the venue clause specifying the courts of the State of California in section 95975(l)(1). Native American Tribes are accustomed to litigating in U.S. Federal Court, and may be more comfortable with the system if this venue clause was changed to U.S. Federal Court. (NEWFOREST)

Response: Section 95975(l)(1) is not merely a venue provision, but it confirms the existing jurisdiction in the California courts. Moreover, federal jurisdiction cannot be unilaterally conferred by ARB's regulation. The Cap-and-Trade Regulation is a California State regulation, in which offset project developers are voluntarily participating in the provisions of the regulation, and ARB believes that it is appropriate to specify the courts of the State of California as the sole jurisdictional forum in order to avoid inter-jurisdictional conflicts in interpretation of the governing statute and the cap-and-trade regulation.

K-24. Comment: Section 95975(l)(1) defines a limited waiver of sovereign immunity by a tribe seeking to list offsets, or for projects located on specified lands. The waiver does not include consent to criminal prosecution and perhaps it should. (SCAQMD4)

Response: While we appreciate the commenter's suggestion, we believe that the requirement for a limited waiver of sovereign immunity in section 95975(l)(1) to include a consent to suit by the State of California, Air Resources Board, in the courts of the State of California, with respect to any action in law or equity commenced by the State of California, Air Resources Board, to enforce the obligations of the Tribe with respect to its participation in the cap-and-trade program is sufficiently inclusive to provide for equal treatment of offset projects conducted on tribal and non-tribal lands.

K-25. Comment: Section 95973(d) requires that "Land that is owned by any person, entity or tribe within the external borders of such Indian lands" must demonstrate the existence of a limited waiver of sovereign immunity between ARB and the governing body of the Tribe. There are two ways to interpret "external borders of such Indian lands." Since the term "Indian lands" uses the definition at 25 USC section 81(a)(1), which defines the term to mean Tribally owned lands, the most literal interpretation would be that it is referring to lands owned by parties other than Tribes (persons or entities) that are surrounded by Tribal lands. However, the use of the term "external borders" implies the section is referring to land owned by any person, entity or Tribe located within the boundaries of the Tribe's reservation, since the word "borders" is usually used in connection with the borders of a reservation. This second interpretation makes the most sense. However, regardless of which way this provision is interpreted, as written it does not make legal sense. It will require landowners who are not Tribes, but who are persons or entities owning land on reservations, to obtain a limited waiver of sovereign immunity from the Tribe. There are three kinds of land ownership on most reservations: land owned by Tribes, land owned by individual Indians and held in trust by the United States, and land owned in fee by non-Indians. The Tribe has no ownership of the latter two categories of land, has no jurisdiction over non-Indian owned land, and has minimal jurisdiction over the use of individual Indian owned land because of its trust status. As a result, the Tribe would have no involvement in a decision by an individual Indian or non-Indian landowner to put his or her land into an Offset Project. For this reason, there is nothing in connection with the Offset Project over which the Tribe would be waiving its immunity. It would therefore correctly refuse to provide such a waiver, and thus the provision as written would have the effect of excluding all non-Indian and individual Indian owned lands within reservations from participating in Offset Projects. Further, there are no legal barriers to ARB suing such land owners, so the section is unnecessary. ARB thus does not need a waiver of sovereign immunity to enforce carbon agreements against such persons or entities, since such persons are susceptible to suit in courts of competent jurisdiction in the same manner as any other person or entity. As a result, this subsection is both unnecessary and will have the effect of excluding all non-Tribally owned land within the external borders of Indian lands from participating in ARB offset projects. For these reasons, we recommend that subsection 95974(d)(3) be removed from the regulation and the requirements on Tribal limited waivers of sovereign immunity should be limited to land owned by Tribes. (MARTINN2)

Response: We agree with the commenter that the second interpretation is the only valid interpretation, and it is unclear how the commenter developed the first interpretation. We understand “within the external borders of such Indian lands” to refer to land owned by any person, entity, or Tribe located within the boundaries of the Indian lands (as defined in 25 U.S.C. section 81(a)(1)). We also believe that the commenter has misinterpreted 25 U.S.C. section 81(a)(1) by stating that this only includes tribally owned lands. 25 U.S.C. section 81(a)(1) defines Indian lands not exclusively as tribally owned lands, but as including lands held by the government in trust for a Tribe. We also note that, while the commenter listed three types of land ownership on most reservations, there may be more than three types of land ownership, including (1) land owned by the federal government in trust for the Tribe, (2) land owned in fee by the Tribe, (3) land owned in fee by members of the Tribe, (4) land owned by non-tribal members in fee, and (5) land owned by the federal government in trust for a member of the Tribe.

We disagree with the commenter that the provision requiring a limited waiver of sovereign immunity for land that is owned by any person, entity, or Tribe within the external borders of Indian lands as defined by 25 U.S.C. section 81(a)(1) does not make legal sense. In fact, and contrary to the commenter’s claim that the Tribe has no jurisdiction over land that it does not own because "the Tribe would have no involvement in a decision by an individual Indian or non-Indian landowner to put his or her land into an Offset Project," it is ARB’s understanding that lands within the external borders of Indian lands, as defined by 25 U.S.C. section 81(a)(1), are subject to sovereignty claims by the Tribe, specifically when such claims arise in the context of the Tribe’s exercise of governmental power over the land in question. While the commenter may be correct that some Tribes might refuse to enter into a limited waiver of sovereign immunity with ARB in relation to offset projects located within the external borders of Indian lands, and that it is possible that in a number of cases a refusal by a Tribe to consent to suit might mean that a project within the external borders of its Indian lands will not go forward, ARB does not agree that all Tribes would refuse to enter such waiver. ARB believes that a limited waiver of sovereign immunity by the Tribe is necessary in order to protect the ability of the State to enforce its interest in the proper functioning of the cap-and-trade regulation with respect to project operation within the external borders of Indian lands.

K-26. Comment: Section 95975(1)(1) requires that the governing body of a Tribe must enter into a limited waiver of sovereign immunity and "This waiver must include a consent to suit by ARB and the State of California, in the courts of the State of

California, with respect to any action in law or equity commenced by ARB or the State of California to enforce the obligations of the Tribe with respect to its participation in the Cap and Trade program, irrespective of the form of relief sought, whether monetary or otherwise." However, pursuant to long-standing U.S. Supreme Court decisions, Tribes in most states lack the legal authority to consent to be sued in state courts. In Kennerly vs. District Court of the Ninth Judicial District of Montana et. al., (400 U.S. 480 (1971)), the Court held that only Congress has the authority to give state courts jurisdiction over Tribes. In 1953, Congress enacted what is commonly known as Public Law 280, giving states the right to assume civil and/or criminal jurisdiction over Indians in their states. That law was amended in 1968 to require Tribal consent before a state could assume such jurisdiction. While California is a "280 state," a state that used the authority of the 1953 Act to assume state court jurisdiction over Tribes and Indians living on a reservation in California, its authority extends only to tribes and Indians in California. A few other states also assumed authority through Public Law 280, but doing so gave the courts in that state civil jurisdiction over the Indians in that state. It did not give California courts jurisdiction over Indians in those states. The Supreme Court made in clear in Kennerly that these statutes are the only ones in which Congress has granted to states the authority to assert jurisdiction over reservation Indians or Tribes and that without such authority, even consent by a Tribe or an individual Indian living on a reservation to be sued in state court is invalid. As a result, under the modified text of the regulation, only Tribes and Tribal members in California will be able to consent to be sued in California state courts, such that this provision will exclude the vast majority of Tribes from participation in carbon offset programs. The provision would, in particular, exclude most Tribes with significant forest land holdings and potential for Forest Offset Projects. There are other possible ways for ARB to ensure Tribes comply with their Offset Project agreements. We recommend that ARB provide a generic obligation on the part of Tribes to be bound, with the specifics worked on a case-by-case basis. Under this approach, the language in sections 95975(1)(1) and (2) could be replaced with "For projects on Tribal lands, the governing body of the Tribe must agree to such provisions as are necessary to ensure the terms of the Offset Project are enforceable. ARB will work with each Tribe on a case-by-case basis to develop enforceable terms that are also consistent with the law—on Tribal jurisdiction as established by the courts and Congress." Tribes cumulatively own over 18 million acres of forest land. By providing flexibility for Tribes in this manner, ARB will enable this forest land to contribute to carbon reduction without sacrificing ARB's appropriate concern that Offset Agreements be fully enforceable. (MARTINN2)

> **Response:** We disagree with the commenter that California courts would not have jurisdiction over offset projects conducted on Indian lands of a Tribe that voluntarily submits to the jurisdiction of California pursuant to the regulation. While Public Law (P.L.) 280 may not give California courts jurisdiction over Indians in other states, this law is irrelevant to the issue of tribal consent to suit, which is what the commenter is purportedly addressing. It may be that some Tribes lack capacity to consent to suit in California courts, but the case cited by the commenter, *Kennerly v. District Court of Ninth Judicial Dist. of Mont.* (400 U.S. 423 (1971)) does not stand for that proposition, or the proposition that

federal authorization is required before a tribe may give its consent. (ARB assumes that the commenter erred in citing to 400 U.S. 480, instead of 400 U.S. 423, when discussing *Kennerly*). *Kennerly* was decided on the basis that a tribal council's resolution vesting concurrent jurisdiction over civil matters in the tribal and state courts was ineffectual under P.L. 280 because the state had not acted through its legislature to assume jurisdiction, and was invalid under the 1968 amendments to P.L. 280 because the resolution authorizing concurrent jurisdiction had not been adopted by the Tribe's membership. (Id., 425-429.) *Kennerly*, in any event, has no application to California, which was one of five states on which P.L. 280 conferred civil jurisdiction without the procedural requirements prescribed for either the state or the Tribe that were at issue in that case. As the commenter acknowledges, there is no question that a Tribe in California can validly consent, by agreement, to the application of California law and to suit in a California court, but ARB disagrees that Tribes outside of California will not be able to provide valid consent.

K-27. Comment: Section 95975(1)(3) notes that "For offset projects located on Indian lands, as defined in 25 U.S.C. section 81(a)(l), the Tribe must also provide ARB with proof of federal approval of the Tribe's participation in the requirements of the Cap-and-Trade Program." ARB is correct in requiring that any Offset Project agreement be approved by the Department of Interior in its capacity as trustee of Indian land. However, to our knowledge, the Department has yet to establish a policy on such approvals, which could delay its action on such approval indefinitely. Our coalition urges ARB to work with us and other involved groups to educate the Department of Interior about the carbon market and the importance of developing a policy for acting on Offset Project agreements entered into by Tribes and by individual Indians whose land is held in trust by the United States. (MARTINN2)

Response: See the response to Comment K-21. This response only addresses those portions of the comment directly pertaining to the modified regulatory language in section 95975(l).

K-28. Comment: ACR believes the language in these sections, regarding offset projects on Tribal lands, is in some respects inconsistent with federal Indian policy as established by the courts and Congress, and will likely exclude most if not all offset projects on Tribal lands. This is because: Tribes generally lack jurisdiction over lands owned by individual Indians and non-Indians within the borders of reservations, and thus are unable to grant a waiver of sovereign immunity; Tribes in most states will not be willing, and/or do not have the legal authority, to consent to suit in California courts, per established Supreme Court decisions and Congressional acts; There is currently no clear Department of Interior policy regarding federal approval of Tribes' participation in the cap-and-trade program. However, we believe alternate language is possible in each case that achieves ARB's objective of enforceability of offset contracts on Tribal lands. ACR has submitted separate, detailed comments on this issue jointly with Van Ness Feldman, EcoAnalytics, and Finite Carbon Corporation. See "Native American Tribal Coalition ARB comments," submitted on August 10, 2011. (MARTINN3)

Response: We disagree with the commenter that Tribes are not able to grant limited waivers of sovereign immunity (See the response to Comment K-25). We also disagree with the commenter's claim that most Tribes do not have authority to consent to suit in California (See the response to Comment K-26). Moreover, we included modified language allowing participation of Tribes in the Cap-and-Trade Regulation if they provide proof of federal approval or documentation that such proof is not required (See the response to Comment K-21).

K-29. Comment: While we are supportive of efforts to ensure programs and projects undertaken through this regulation are in accordance relevant statutes governing sovereign relations with Tribes, the requirements for "limited waiver of sovereign immunity" in the regulation are much too vague at this point to provide the public or tribes with any understand of how limited or broad such a waiver might be. While enforcement of any portion of this regulation is imperative, vague and undefined terms may result ARB's inability to fully enforce the provisions of the rule. (FRIENDSOFEARTH2)

Response: We disagree that the provision related to "limited waivers of sovereign immunity" is too vague or that it would result in the inability to fully enforce the provisions of the regulation. In fact, ARB believes that the requirement of entering into a limited waiver of sovereign immunity, as well as the requirement that this waiver include a consent to suit, are sufficiently clear to provide the public and Tribes with an understanding of what is required under these provisions of the regulation. Each Tribe that wishes to participate in the Cap-and-Trade Regulation would be required to enter into an individual limited waiver of sovereign immunity with ARB in accordance with the Tribe's Constitution or other organic laws, by-laws and ordinances, and applicable federal laws. Given the independent, sovereign nature of each federally recognized Indian Tribe, and the unique legal structure of each Tribe, adding additional prescriptive regulatory requirements beyond those already listed in the regulation would be problematic and overly restrictive.

K-30. Comment: The sole form of dispute resolution contemplated under the regulations is litigation. Arbitration is the preferred mechanism. The regulations should require arbitration with court jurisdiction only to enforce the arbitration award. Arbitration is more cost effective for all parties, more collaborative, shorter in duration and can be handled across the country under either JAMS or AAA rules. In cross-jurisdictional transactions, such as the majority that will take place under the forestry protocol, arbitration is fairer because neither party can gain an unfair advantage. As will be explained in the Navajo example below, arbitration is a compromise because it allows objective rules to be relied on by the parties while still satisfying the requirement that the Navajo forum be utilized. Utilizing arbitration would be in line with the majority of contracts entered into nowadays. (UBCSSB)

Response: We do not agree that arbitration is necessarily the preferred mechanism for dispute resolution. While arbitration may be a common means of resolving commercial disputes, ARB does not believe it would be satisfactory as a means of enforcement of the State's interests based upon project participant conduct, in particular due to the fact that ARB's regulatory interests may require resolution of certain questions through the issuance of an authoritative and binding judicial precedent.

K-31. Comment: Requiring that all disputes be handled in the Courts of the State of California is too onerous and will dissuade tribes from participating. The number of tribes in California with sufficient forestry assets, or with land bases large enough to participate in the other protocols, is very limited. As such, the vast majority of offset projects will be located in other states. Requiring that all disputes be handled in California is only appropriate if the project is in California. The language needs to make clear that the limited waiver of sovereign immunity does not signify that the tribe's forum cannot be utilized for resolving disputes. While most tribes do not have courts, for those that do, it may make sense in some limited instances to allow the tribe's forum be utilized. For example, the Navajo Nation has 5,311,975 acres of forested lands. If the requirement is that disputes have to be in a forum other than the Navajo justice system, then they will not be able to participate in the California program. While the Navajo Nation readily enters into limited waivers of sovereign immunity, they have a blanket prohibition on allowing dispute resolution, arbitration, litigation and the like in forums other than the Navajo's forum. Their justice system is recognized as highly sophisticated and reliable. Recently, Key Bank entered into a $60 Million financing agreement containing a limited waiver of sovereign immunity with a forum selection clause requiring resolution of disputes within the Navajo system. *See http://www.pitchengine.com/keybank/keybank-and-navajo-nation-partner-on-groundbreaking--60-million-deal-governed-entirely-by-navajo-law/71893/*. (UBCSSB)

Response: We disagree with the commenter that requiring disputes to be handled in the Courts of the State of California is too onerous. It is ARB's understanding that each Tribe may have a completely separate and distinct judicial system, or none at all; and while ARB appreciates the commenter's reference to the Navajo's developed justice system, California must also take into consideration the fact that not all Tribes are similarly situated, either in terms of landbase or in the nature of their justice systems. Moreover, requiring ARB to submit disputes into these varied jurisdictions is neither practical nor would it serve the interests of the State in providing a consistent choice of law and judicial forum for all offset projects, regardless of where they were conducted.

K-32. Comment: The party with rights to bring actions to enforce the regulations should only be the Air Resources Board. While the Air Resources Board is a subdivision of the State of California it does not have the same connotations for tribes as the State itself. Given the hundreds of years of history in which tribes have been held to be free from suit by the States, it is likely to "feel" unacceptable to tribal membership to allow the State the ability to sue tribes. In our opinion, it will be very difficult to convince a tribe to agree to being sued by the State of California in the Courts of the State for 100 years. (UBCSSB)

Response: We agree with the commenter that the party with rights to bring actions to enforce the regulations is the State of California, Air Resources Board. We modified the language to more clearly reflect this and believe the modifications effectively address the commenter's concern. This response only addresses those portions of the comment directly pertaining to the modified regulatory language in section 95975(l).

K-33. Comment: The allowable remedy should not be monetary sanctions. The waiver of sovereign immunity should only be for the limited purposes of specific performance or injunction, and any other purposes necessary to fully enforce the regulations. If the ARB is not willing to accept such a limitation, then at the very least, the regulations should state that in no instance should enforcement of any kind be allowed against any assets of the Tribe itself and in no instance should enforcement of any kind be allowed against any assets of the Tribe except those revenues generated by the Cap-and-Trade Program. This type of provision is in line with most contracts with tribes. Typically monetary sanctions are limited to the revenue stream related to the underlying contract because like other governments there is very little "general fund" monies without an associated line item that are available. (UBCSSB)

Response: We believe that the availability of relief, monetary or otherwise, against offset project operators, including Tribes and entities created by Tribes, is necessary not only to ensure equitable and enforceable treatment of all offset projects, but also to ensure the environmental integrity of the offset program. In fact, providing different treatment for Tribes versus non-tribal offset projects would be contrary to the concept of voluntary participation in the offset program on an equal basis. As such, ARB believes that to limit an allowable remedy to specific performance or injunction, or to prohibit enforcement against assets of the Tribe itself, would be antithetical to this objective. Since the Cap-and-Trade Regulation does not require a contract between ARB and any particular Tribe, it is unclear how the commenter's statements on the "typical" nature of contracts with Tribes is applicable to the regulatory language on limited waivers of sovereign immunity.

K-34. Comment: Proof of federal approval of a tribe's participation in the Cap-and-Trade Program under 25 U.S.C. section 81(a)(1) may not be needed. Approval under 25 U.S.C. section 81(a)(1) should not be required if under 25 U.S.C. section 81(c) agreements related to offset projects are exempted or determined to not be covered under that subsection. There is discussion taking place with the Bureau of Indian Affairs and the Secretary of the Interior to exempt these offset projects. As such, the language should state that such approval is needed only if the Department of Interior has made clear that such approval is needed. (UBCSSB)

Response: See the response to Comment K-21.

K-35. Comment: The language needs to apply both to tribes and special purpose entities created by tribes. The language, as currently drafted, is applicable only to tribes. It is highly likely that for an offset project on the types of land described in the regulations, that a tribe would create a special purpose entity either under tribal or state law which may not be wholly-owned by the tribe. We suggest using the term "contracting party" in addition to "Tribe." (UBCSSB)

> **Response:** We agree with the commenter that the language should apply both to Tribes and to entities created by Tribes. We modified the definition of "Tribe" to include "any entity created by a federally-recognized Indian Tribe."

K-36. Comment: The language should contain conditions, which much be satisfied prior to commencement of an action by the ARB. Each of the following conditions should be met: (i) the claim is brought by the Air Resources Board ("ARB") and not by any third party; (ii) the claim alleges a material uncured breach by the Tribe (or contracting entity) of one or more of the specific obligations set forth in the Regulations; (iii) the claim seeks some specific action, or discontinuance of some action by the Tribe (or contracting entity) to bring it into full compliance with the duties and obligations expressly assumed by it under the Regulations and does not seek money damages (including special, consequential, incidental, punitive, or exemplary damages); (iv) the claim is first made in a written notice to the Tribe (or contracting entity), stating the specific action or discontinuance of action by the Tribe (or contracting entity) which would cure the alleged breach or non-performance and the Tribe (or contracting entity) shall have failed to cure such breach or non-performance within sixty (60) calendar days (or such additional time as may be set forth in such notice) after its receipt of such statement; and (v) the Parties have met and conferred prior to the commencement of any action. (UBCSSB)

> **Response:** We disagree that these prescriptive conditions should be included in the regulatory language. See the response to Comment K-29. We disagree with the specific conditions presented by the commenter, based on the reasons listed in the response to Comment K-33.

K-37. Comment: The language regarding the limited waiver of sovereign immunity is vague. Limited waivers of sovereign immunity can be extremely controversial for Tribes, especially when the underlying parameters of the waiver are undefined. This simply will not work for tribes. The vague language as written will surely dissuade tribes from participating in the Cap-and-Trade Program. The language should explain with specificity what enforcement could be sought against a tribe, that officials of the tribe are exempt, that rights are not created for third parties, and define what types of relief and remedies are permitted. The language above also does not suggest the exact language that will be needed in the limited waiver of sovereign immunity. Tribes need to be put on notice as to exactly what they are agreeing to. Below is language that we believe should be adopted.

The Tribe (or contracting entity) hereby expressly waives its respective rights of sovereign immunity from unconsented suit but only for the limited purpose of permitting the commencement, maintenance and enforcement of arbitration by the other Party to enforce the regulations found at Subchapter 10 Climate Change, Article 5, Sections 95800 to 96022, Title 17, California Code of Regulations ("the Regulations"), for the limited purposes of specific performance or injunction, and any other purposes necessary to fully enforce such regulations. The Tribe (or contracting entity) grants the limited waiver of its right of sovereign immunity herein, and action may be initiated if, and only if, each and every one of the following conditions is met: (i) the claim is brought by the Air Resources Board ("ARB") and not by any third party; (ii) the claim alleges a material uncured breach by the Tribe (or contracting entity) of one or more of the specific obligations set forth in the Regulations; (iii) the claim seeks some specific action, or discontinuance of some action by the Tribe (or contracting entity) to bring it into full compliance with the duties and obligations expressly assumed by it under the Regulations and does not seek money damages (including special, consequential, incidental, punitive, or exemplary damages); (iv) the claim is first made in a written notice to the Tribe (or contracting entity), stating the specific action or discontinuance of action by the Tribe (or contracting entity) which would cure the alleged breach or non-performance and the Tribe (or contracting entity) shall have failed to cure such breach or non-performance within sixty (60) calendar days (or such additional time as may be set forth in such notice) after its receipt of such statement; and (v) the Parties have met and conferred prior to the commencement of any action.

This limited waiver is applicable to the ARB only and does not apply to third parties. This limited waiver shall also not be construed as a waiver of any immunity of any elected or appointed officer, official, member, manager, employee, or agent of the Tribe (or contracting entity). In no instance shall enforcement of any kind be allowed against any assets of the Tribe itself. In no instance shall enforcement of any kind be allowed against any assets of the Tribe except those revenues generated by the Cap-and Trade Program that have not been distributed to the Tribe's government.

The Tribe and ARB hereby consent to the jurisdiction of the Tribe's court, the United States District Court, the United States Court of Appeals, and the United States Supreme Court or, if the offset project is located in California and the Federal Courts decline to take jurisdiction of the matter, the County Superior Court in which the Tribe's government is located, and/or the Court of Appeal of the State of California, but they do so separately and collectively solely for the purposes of enforcing arbitration pursuant to this Agreement and enforcing an arbitral award entered in connection with the resolution of a dispute arising out of this Agreement. No other action may be maintained in any court of law. (UBCSSB)

Response: See the response to Comment K-29. In relation to enforcement actions, ARB believes the regulatory requirements, which would apply to all offset projects, are clear, and including specific language limiting the nature of enforcement is contrary to ARB's interests in ensuring the operational and environmental integrity of the cap-and-trade program. Moreover, listing the specific language for a limited waiver of sovereign immunity in the regulation would be impractical for the reasons listed in the response to Comment K-36. In addition, ARB believes that the provisions regarding arbitration in this comment are impractical and unsuitable to ARB's purpose in this regulation for the reasons stated in the response to Comment K-30.

L. MARKETS

Applicability

L-1. Comment: LADWP recommends that section 95814(b) Other Registered Participants be deleted.

~~(b) Other Registered Participants.~~

~~(1) The following entities do not qualify to hold compliance instruments but may qualify as a Registered Participant to serve in the following functions:~~

~~(A) An offset verifier accredited pursuant to section 95978;~~

~~(B) A verification body accredited pursuant to section 95978;~~

~~(C) Offset Project Registries; or~~

~~(D) Other third-party registrants Early Action Offset Programs approved pursuant to subarticle 14.~~

~~(2) To qualify as a Registered Participant the entity must obtain registration approval from the Executive Officer pursuant to section 95830(c).~~

The term "Registration" in section 95814 is specifically required for holding any type of account and holding compliance instruments. It does not specify any other purpose. The type of participants listed as "other participants" includes independent third party entities that are involved in emissions verification for covered entities or offset verification for offset projects. By the very nature of their independent role, they should not be involved with the Cap-and-Trade program as a registered participant as this would introduce a potential conflict of interest, which could harm or invalidate the verification process for the projects and emissions they verify. There are other mechanisms in the MRR and Cap-and-Trade regulation that would allow ARB to certify or track entities involved in verification without including them as a registered participant. (LADWP4)

> **Response:** We disagree with the interpretation that the term "Registration" in section 95814 is specifically required for holding any type of account and holding compliance instruments, and that section 95814 does not specify any other purpose. We believe that section 95814(b)(1) specifies that the following entities do not qualify to hold compliance instruments, but may qualify as a Registered Participant to serve in the listed functions. It also specifies, under (b)(2), that to qualify as a Registered Participant, the entity must obtain registration approval from the Executive Officer. In this instance, registration approval is a discretionary action by the Executive Officer, not an automatic ministerial action.

L-2. Comment: Section 95814(a)(3) would add derivatives clearing organizations that take only temporary possession of compliance instruments to the definition of "voluntary associated entities." PG&E recommends that ARB define "temporary possession" as it is used in section 95814(a)(3) so as to ensure that derivatives clearing organizations that are claiming to qualify as voluntary associated entities pursuant to section 95814(a)(3) are in fact only taking temporary possession of allowances for the amount of time needed to provide the market clearing service and the transfer of compliance instruments. Otherwise, derivatives clearing organizations could use this section to exempt themselves from the registration information required of other entities by section 95830(c)(1)(D). Modify section 95814(a)(3) as follows:

> (3) An entity providing clearing services, <u>or clearing entity</u>, in which it takes only temporary possession of compliance instruments for the purpose of clearing transactions between two entities registered with the Cap-and-Trade Program<u>. Temporary possession shall only constitute the period of time required to facilitate clearing and the transfer of compliance instruments between parties. A clearing</u> entity ~~must be~~ <u>is</u> a derivatives clearing organization as defined in the Commodities Exchange Act (7 U.S.C. subsection 1a(9)) that is registered with the U.S. Commodity Futures Trading Commission pursuant to the Commodities Exchange Act (7 U.S.C. subsection 7a-1(a)). (PGE4)

> **Response:** We believe that section 95831(a)(5) makes the suggested modification to section 95814(a)(3) unnecessary. The 15-day changes to the regulation also added new section 95831(a)(5), a new type of account, Exchange Clearing Holding Accounts, specifically for voluntary associated entities registered pursuant to section 95814(a)(3). This section clarifies that the accounts administrator will create an exchange clearing holding account for the entity providing clearing services. Entities may transfer compliance instruments to exchange clearing accounts only for the purpose of transferring control of the instruments to the entity performing the clearing function. The clearing entity may only transfer the compliance instruments in its exchange clearing holding account to the account designated by the entity receiving the allowances under the transaction being cleared.

Trading / Trade Conduct

Secondary Market / Reversals / Exchange Clearing Holding Accounts

L-3. Comment: Section 95920(a) specifically states the holding limit applies to each voluntarily associated entity. Applying this concept to a clearinghouse disregards its basic function. Such an entity does not make choices on its investment decisions, but serves the needs of the market participants. It is not clear how such an entity could take measures to comply; the holding limit for an individual covered entity has many source and company specific terms that are not easily calculable or even known to the exchange, and the exchange will only know the anticipated low of allowances mere days before they are transferred to the exchange clearing holding account, and then immediately transferred out again. Also, the exchange will receive allowances from the seller's clearing firm. It is also worth noting that clearing firms may need a similar exemption as they will be pooling their selling customers' allowances to transfer to the exchange. Finally, the rule already counts, in the holding limit for the purchaser, any instruments which have been delivered from an exchange clearing trading account, (see (b)(3)). Exchange-traded environmental contracts are physically settled on specific expiration dates. For the California market, this could mean the transfer of tens of thousands of allowances on a single day. An unintended consequence of the proposed holding limit approach is that no clearinghouse will be able to serve the critical role as a true intermediary in any physically-settled contracts due to the likely violation of the holding limit levels on delivery days. To address this issue, we recommend modifying section 95920(b)(1). Delete the applicability of a holding limit to exchange clearing holding accounts or modify section 95920(b)(2) as follows:

> (2) The holding limit calculation will not include allowances contained in limited use holding accounts created pursuant to 95831 or exchange clearing holding accounts except pursuant to section 95920(b)(3) below." (GREENX)
>
> **Response:** We acknowledge the concern expressed in the comment, but we do not agree with the suggested change. We believe that the text added as section 95920(b)(3) is sufficient to prevent calculation of holding limits from interfering with the operation of exchange clearing entities, as it counts the allowances which are part of transfers against the holding limits of the party listed as recipient of the transfer not the exchange clearing entity.

L-4. Comment: We urge ARB to not rely on "reversal" of trades by the Executive Officer (section 95920(b)(4)). This provision will interfere with the sanctity of contract, result in litigation between market participants, could result in gaming where a party may try to unwind the least economic favorable contract(s), and will cause a lack of confidence in exchange-traded and over-the-counter contracts. We recommend that the rule be revised to instead allow for a cure period of fifteen days to allow market participant to sell any excess allowances, and if the participant does not do so, then the penalties already contemplated in (b)(4) would apply. ARB may also wish to make clear that the penalties will increase for repeat offenses. These changes will facilitate the efficient use of exchange traded contracts, which brings the benefits of market liquidity, price transparency and a safe and secure venue for companies to manage their short and long term risk, and will help prevent unintended consequences and the gaming opportunities described above. At the same time, it preserves ARB's authority to oversee and monitor the program, and take appropriate action if needed. Modify section 95920(b)(4) as follows:

> (4) If the Executive Officer determines that a reported transaction, whether or not it has been ~~yet~~ recorded into the tracking system would result in an entity's holdings exceeding the applicable holding limit, then the Executive Officer shall provide notice to the entities involved, and allow a fifteen day cure period for correction of the potential exceedance. The potential exceedance may be cured by a sale of the excess credits, or transfer of credits into a compliance account. If the potential exceedance has not been corrected by the end of the fifteen day cure period, ~~then the Executive Officer shall not approve the transaction pursuant to section 95921(a)(l). If the violation is not discovered until after the transaction~~

~~is recorded, then the transaction may be reversed pursuant to section 95921 (a)(2) and~~ penalties may be imposed pursuant to section 96013. Such penalties may increase due to repeated violations of this section. (GREENX)

Response: We acknowledge the concern expressed in the comment. However, we decided to respond by adding new text to section 95921 to deal with deficient transfer requests. We introduced the term “transfer request” to draw a distinction between the underlying market “transaction” and the request by the transacting parties to the accounts administrator to transfer the compliance instruments between accounts on the tracking system. We have final control over our recognition of the entity that holds an allowance for compliance purposes, and do not wish to interfere with market mechanisms. Therefore, section 95921(b) was revised to state that if we cannot resolve deficient transfer requests we may reverse transfers, not the underlying transaction.

We identified two cases that should be addressed separately. First, if the deficiency is detected prior to recording into the tracking system, the parties will be notified and should correct the deficiency within the transaction reporting time limit set in section 95921(a)(1)(A). If this cannot be done, they should resubmit or withdraw the request. Second, if the deficiency is detected after the transfer has recorded, we propose a “cure” period of five days. We find the fifteen-day cure period proposed in the comment to be far greater than what is needed to fix any violations of our rules.

L-5. Comment: PG&E is concerned about the lack of detail with respect to trades and raises the following questions. If ARB opts to not include this type of detail in the regulation, PG&E requests clarification regarding where this type of detail will be presented.

- Can ARB specify a timeframe at which point the transaction cannot be reversed?
- How will ARB resolve the circumstance where it determines a transaction should be reversed but a subsequent transaction has taken place such that the initial transaction can no longer be reversed?
- How does trade information get transferred? Via web application? XML? Paper? (PGE4)

Response: Under the revisions made to section 95921(b) in the second 15-day changes to the regulation, we will retain the ability to reverse the recording of a transfer request into the system, but do not require reversal of an underlying transaction. In addition, such a reversal would not be automatic, but only done if the parties to the transfer do not correct the deficiency. As deficient transfer requests represent some failure to follow the regulation, it is also possible that the remedy will be the imposition of a penalty instead of a reversal. The regulation does not address methods of communication. We will address this topic during the tracking system development and program implementation.

L-6. Comment: While Evolution Markets recognizes the need for ARB to have a mechanism to enforce holding limits and conduct market oversight, we are concerned with provisions in the revised section 95921 that grants the ARB Executive Officer the ability to reverse transactions as a means of enforcement. This mechanism provides ARB an unprecedented enforcement power, which ultimately could be detrimental to trading liquidity and the ability for entities to hedge price risk and comply with carbon reduction targets at the lowest possible cost. Reversing commercial transactions between counterparties creates a host of contractual and compliance issues. The foundation of a properly functioning market is that commercial contracts between counterparties cannot be unwound. An obligation to sell allowances to another counterparty must be met, and once the transfer of allowances and cash has taken place counterparties cannot be expected to reverse this transaction.

Furthermore, such reversals may create a daisy chain of violations of holding limit provisions. In the instance of ARB reversing a transaction, the buyer of allowances will return the allowances to the seller. The seller may have sold the allowances to ensure it did not violate its own holding limits, and the return of allowances from the reversed transaction might then put the seller over its holding limit. Rather than reverse transactions, which could have unintended negative consequences for multiple market participants, Evolution Markets recommends taking punitive action against the entity in violation. In the case of holding limits, this might include providing the entity a set period of time to dispense of excess allowances. (EVMKTS2)

> **Response:** Under the revisions made to section 95921(b) in the second 15-day changes to the regulation, we will retain the ability to reverse the recording of a transfer request into the system, but we do not automatically require reversal of an underlying transaction. Such a reversal would only be done if the parties to the transfer do not correct the deficiency. As deficient transfer requests represent some failure to follow the regulation, it is also possible that the remedy will be the imposition of a penalty instead of reversal.
>
> We clarified the distinction between the act of transferring control of a compliance instrument on the tracking system and the underlying agreement in the secondary market between entities which would result in a transfer. We modified section 95920(b) to replace the term "transaction" with the term "transfer request." We made this change to sections 95920(b)(3) and (4). We also modified section 95920(a) to clarify that the holding limit will be applied to a group of entities with a direct or indirect corporate association. We made this change to reflect a change to the classification of corporate associations in section 95833(a).
>
> The term "transaction" means an understanding among registered entities to transfer the control of an allowance from one entity to another, either immediately or at a later date. The "transfer" of a compliance instrument means the removal of the serial number of a compliance instrument from one account and placement into another account. In the California cap-and-trade program, a transfer will be

affected through a “Transfer Request” submitted by an authorized account representative or an alternate authorized account representative to the accounts administrator in order to register a transfer of allowances between accounts into the tracking system.

We eliminated section 95920(f) because changes to section 95920(a) render the section redundant. We renumbered existing section 95920(g) as section 95920(f).

We modified section 95920(f)(1) to clarify that the holding limit is applied only to allowances, not to all compliance instruments. In addition, the holding limit applies jointly to members of direct and indirect corporate associations, not to members of a discloseable corporate association. We also made this change to sections 95920(f)(2), (3) and (4). We modified section 95920(f)(4) to use the newly defined term “transfer request” in place of the term “transaction.” We made this change to clarify that the accounts administrator will not accept deficient transfer requests. Some stakeholders expressed concern that the provision would require the automatic unwinding of the transaction that resulted in the transfer request.

L-7. Comment: GreenX suggests revising section 95921(c) to exclude holders of exchange clearing holding accounts from the obligation to report the information required to be provided in 95921(c)(4-7). This information potentially will be reported already by the buyer, seller, the buyer's clearing firm and the seller's clearing firm. Any reporting of these transactions by an exchange will be duplicative information, will be overly burdensome for the exchange, and unnecessarily onerous for ARB to process this repetitive information. In addition, since the exchange holding account ills the transparency function of reporting, there is no need for an additional reporting by the exchange or the with respect to the exchange clearing holding account. Modify section 95921(c) as follows:

(c) Information Requirements. The following information must be provided for the accounts administrator to record the transaction~~:~~. Holders of Exchange Clearing Accounts are exempt from providing the information required under 95921(c)(4)-(7). However, exchange clearing holding requests transactional records will be preserved for five (5) years and may be made available, upon reasonable prior written request, to ARB. (GREENX)

Response: New section 95921(g) modifies the information required for transfer requests when submitted by holders of exchange clearing holding accounts. New section 95921(g)(1) exempts these entities from having to include dates, prices, and beneficial holdings information in transfer requests. This information would be in the transfer requests submitted by the entities using the exchange clearing accounts to transfer control of compliance instruments. We agree with stakeholders who commented that requiring this information would be an unnecessary requirement.

L-8. Comment: Section 95831(a)(5), uses the term "Exchange Clearing Holding Accounts." Elsewhere in the rules, "holding accounts" are addressed. We presume that ARB intended that exchange clearing trading accounts would be able to trade with regular holding accounts. In order to make clear that transfers from holding accounts may go to, or from, an exchange holding account. Modify section 95921(a)(2) as follows:

> (2) Except when the transaction is undertaken by the Executive Officer, all transactions <u>shall be</u> between two entities <u>and</u> will involve transfers between two holding accounts <u>and/or an exchange clearing holding account</u>. (GREENX)
>
> **Response:** We made the change to address the requested clarification.

L-9. Comment: The language in section 95922 should be made consistent with that of section 95831 (Account Types). For instance, sub-paragraph (c)(1) refers to surrender (of a compliance instrument) by a covered entity, whereas section 95831 refers to the transfer of compliance instruments from entity compliance accounts to the Retirement Account. (WPTF2)

> **Response:** The language is consistent. Compliance instruments are surrendered by an entity when they are placed in a compliance account by a compliance deadline. The Executive Officer retires surrendered instruments by transferring them to the Retirement Account.

L-10. Comment: In section 95921(d)(3), it is not clear why the accounts administrator has to keep confidential the information concerning the amount and serial number of instruments in an entity's holding account. This would appear to allow manipulation in the secondary market since no one will know who actually has compliance instruments to sell. (SCAQMD4)

> **Response:** We disagree with the comment. If a potential manipulator is unaware of who has allowances in holding accounts, that entity will not be able to estimate the probability of success of a manipulative scheme. The manipulator would also be unable to estimate whether covered entities are short and would need to buy even at higher prices.

L-11. Comment: PG&E is concerned about the addition of sections 95921(d)(1) and (4). PG&E strongly believes that the accounts administrator should not publicly release information on the transaction price and quantity of compliance instruments for any individual transaction. However, PG&E would support release of information on the aggregate price and quantity of compliance instruments sold in any given week, if the release was delayed until a week after the end of the given week. Under section 95921(d)(4), ARB intends for the accounts administrator to release information on the quantity and serial numbers of compliance instruments contained in compliance accounts. Such information should remain confidentially held by the accounts administrator until the end of each compliance period's surrender date. Only information about compliance instruments in retirement accounts, not compliance accounts, should be publicly released. Modify section 95921(d) as follows:

> (d) Protection of Confidential Information. The Executive Officer will ensure that the accounts administrator:
>
> > (1) Releases aggregated information, with names of entities withheld at the end of each week on the transaction price and quantity of compliance instruments for transactions recorded by ARB in the previous week ~~in a timely manner~~;
> > (2) Except as needed for market oversight and investigation by the Executive Officer, protects as confidential all other information obtained through transaction reports;
> > (3) Protects as confidential the quantity and serial numbers of compliance instruments contained in holding and compliance accounts; and
> > (4) Releases information on the quantity and serial numbers of compliance instruments contained in ~~compliance~~ retirement accounts in a timely manner no earlier than the surrender date following the end of a compliance period. (PGE4)

Response: We disagree with the suggested modifications to section 95921(d). In general, we recognize that there are both advantages and disadvantages to the public release of certain types of information, and we wish to balance these. New section 95921(d) (Protection of Confidential Information) was added to address many stakeholders concerns regarding the confidentiality of information reported on the transfer request. At the same time, section 95921(d)(1) was added to ensure that information needed by the market would be released, with the added protections of the restrictions imposed in the rest of the section.

Regular releases of holdings of individual firms may reveal commercially sensitive information on trade strategies that could increase the vulnerability of a participant or of the market as a whole to manipulation. We expect that market participants will have a variety of options to buy or sell allowances, through bilateral transactions, transactions through an intermediary, and exchange transactions in both spot and derivatives markets, as well as auctions. In addition, an entity's holdings are not necessarily indicative of its willingness or ability to sell compliance instruments.

Because compliance instruments cannot be removed from a compliance account except to retire them, the number in compliance accounts is important information to the market on the available supply for trading. Further, information on an entity's compliance with the requirements of an environmental regulation benefits the public interest.

L-12. (multiple comments)
Comment: Section 95921(a)(1)(A) addresses how transactions are reported. What

would happen if a transaction is reported later than three days of settlement of the transaction agreement? The language suggests that it will not be registered because the deadline was not met. We recommend that a penalty be assessed instead of not registering the transaction. (SCAQMD4)

Comment: ARB does not define "settlement of transaction agreement." ARB does distinguish between "settlement date and time" and "transaction agreement date and time" by allowing these two types of information to be sent to the accounts administrator, but these terms are also not defined. It could be difficult for entities to comply with a 3 calendar day requirement if the settlement of a transaction occurs on a Friday and repot of the transaction requires specific signatures. Seven calendar days is more reasonable. Modify section 95921(a)(1)(A) as follows:

> (1) Except when the transaction is undertaken by the Executive Officer, the cap-and-trade program will not register a change in ownership of a compliance instrument until:
> (A) The two parties to the change in ownership report the transaction to the accounts administrator within <u>(7) calendar</u> days of settlement of the transaction agreement. (LADWP4)

Response: We agree that the transfer process and consequences of not meeting the three-day time limit needed clarification. We modified sections 95921(a)(1) and (2) to clarify that all requests for transfer of compliance instruments between accounts in the tracking system must meet the requirements for this article before the accounts administrator will register them into the tracking system. The changes are needed to emphasize the distinction between the transfer request and the underlying transaction that results in the request. Existing section 95921(b) was replaced completely. New section 95921(b) outlines the procedure to be followed when the accounts administrator finds a deficiency in the transfer request submitted pursuant to 95921(a).

New section 95921(b)(1) describes the procedure when a deficiency is detected in a transfer request before it is recorded into the tracking system. New section 95921(b)(1)(A) requires the accounts administrator to inform both the Executive Officer and the entity submitting the request of the deficiency. New section 95921(b)(1)(B) states that the entities submitting the request may resubmit the request with the deficiency corrected within the three-day time limit set pursuant to section 95921(a)(1)(A). New section 95921(b)(1)(C) states that if entities fail to submit the corrected transfer request within the time limit, they must either withdraw the transfer request or submit a new request for transfer.

We created this procedure to ensure that some quality control checks are made when a transfer request is submitted. We anticipate that most deficiencies will be minor, such as failure to include correct account numbers, compliance instrument serial numbers, or other required information fields. We believe that these problems should be remedied within the existing requirement to submit a transfer request within three days of the settlement of a transaction that results in a request for transfer.

Timely requests for transfer are essential to proper functioning of the market and to market oversight. Delays in a transfer request may, for example, prevent the recipient from transferring instruments to settle another transaction. Delays in transfer requests could also allow an entity to, in effect, control more allowances than permitted by the holding limit. We believe three days is an adequate amount of time to submit transfer requests.

Transaction Data: Information Requirement

L-13. (multiple comments)
Comment: MSCG strongly recommends eliminating the "time" portion of the reporting requirement in sections 95921(c)(4) and (5). Current industry practices do not "time stamp" trades or agreements, nor do trade capture and settlement databases have fields for this datum. Complying with this requirement is likely to impose substantial costs for information technology expenditures. Furthermore, it will require a culture shift among traders to ensure they record the transaction times, suggesting a high rate of unintentional errors, at least in the early stages of trading. Weighed against these issues, the market monitoring benefits of time stamping do not seem likely to be of high value. FERC proposed "time stamping" in its recent "EQR" NOPR (RM10-12). Generally, the industry strongly opposed this addition in comments, due to the disproportionate cost/benefit ratio. FERC has yet to rule. While we believe elimination of time stamping would be the best decision, irrespective of FERC's ultimate ruling, at a minimum, we would urge ARB to hold off instituting such a requirement until and unless FERC does so. (MSCG3)

Comment: Section 95921(c) delineates the transaction information that must be submitted to the accounts administrator. Section 95921(c)(4) and (5) require that time and date be submitted for transactions agreements and settlements. WSPA does not believe that such information is necessary and will be difficult to track. WSPA recommends that sections 95921(c)(4) and (5) be deleted. (WSPA3)

Comment: Disclosure of unnecessary information will place significant unnecessary reporting burden (i.e. Time of transaction, time of settlement, price) and should be deleted in section 95921(c)(4) and (5). (CCEEB3)

Response: The original language of section 95921(c)(4) and (5) did not change, and therefore is outside the scope of the first 15-day changes to the regulation. However, we agree with stakeholders who commented that the "time of transaction" is not meaningful for many transactions. The requirement for the transfer request to include the time of the transaction settlement was removed from sections 95921(c)(4) and (5). Because the remaining comments fall outside the scope of the notice, no further response is required.

Executive Officer's Tools

L-14. Comment: Section 95921(f) provides an extensive list of options available to the Executive Officer in the event that a registered entity violates any of the provisions of section 95921. MID and NCPA recommend deleting section 95921(f)(1) as the remedies outlined in this section and throughout the proposed regulation are sufficient to dissuade a covered entity from engaging in improper market activities. Removing a covered entity's compliance instruments directly from its holding account effectively results in a taking, and unnecessarily punishes those covered entities that have a surrender obligation whose costs are directly borne by ratepayers. Modify section 95921(f)(1) as follows:

> (~~1) Reduce the number of compliance instruments a covered entity or opt in covered entity may have in its holding account below the amount allowed by the holding limit pursuant to section 95920;~~

In addition, subsection (A) below, by its own terms, applies only to revocations. Thus, the reference there to suspended accounts is not appropriate. Subsection (B) only applies in cases where (A) applies. Moreover, it does not make sense to require a suspended account that continues in existence and will be entitled to participate in the program in the future to be emptied of all allowances. Thus MID recommends the following changes.

> (f)(3) Suspend or revoke the registration...pursuant to section 95830; ~~or~~
>
> (A) If registration is revoked ~~or suspended~~ the entity must sell or voluntarily retire all compliance instruments in its holding account within 30 days of revocation; and
>
> (B) If registration is revoked ~~or suspended~~ and the entity fails to sell… (MID3, NCPA3)

Response: We disagree with the suggested modifications to section 95921(f)(1). The provision is not for removal of compliance instruments, but a reduction in the maximum number that may be held by a group of associated entities.

We disagree with the comment's characterization of suspension of an account. An entity's account will only be suspended in response to significant violation of this regulation. Only a registered entity may hold compliance instruments. An entity whose account is suspended loses all privileges associated with participation in the cap-and-trade program, including the ability to hold compliance instruments. Therefore, we did not make the suggested changes to section 95921(f)(3).

L-15. Comment: Section 95921(f) defines the actions that may be taken if an entity violates any provision of this article. The actions are quite broad, and it seems there should be some requirement to preclude arbitrary enforcement, such as some kind of proportional requirement, and some provision for appeal. (SCAQMD4)

> **Response:** We established a wide range of actions, which are augmented by our penalty-setting authority, to anticipate a wide range of severity of regulation violations. ARB's enforcement policy governs the severity of enforcement as well as discussions with violators.

Beneficial Holding

L-16. Comment: The existing language in section 95921(e)(1) would not prohibit a trade in which the parties do not report an ownership interest at all. Modify section 95921(e)(1) as follows:

> (1) A trade in which the parties to a transaction reported to the accounts administrator fail to disclose the ownership interest of a registered account holder in the sale or purchase of a compliance instrument before ~~until after~~ a transaction is recorded by the accounts administrator. (SCAQMD4)

> **Response:** We replaced section 95921(e)(1) with new section 95921(a) to clarify requirements for transfer requests. New section 95921(b) describes the process when a transfer request is found to be deficient.

L-17. Comment: SCE requests that ARB clarify how beneficial holding will affect the calculation of the Holding Limit of the principal and that of the agent. Section 95920(h) states that the "application of the holding limit will treat beneficial holding by an agent as part of the holding of the owner." SCE reads this to mean that beneficial holding, even if technically located in the holding account of the agent, will count toward the holdings of the principal or "owner." SCE recommends that ARB clarify this application of the Holding Limit. (SCE3)

> **Response:** Section 95920(h) was renumbered to section 95920(g) and clarified so that the holding limit will include a beneficial holding by an agent against the holding limit of the principal for whom it is held.

L-18. Comment: Section 95922. ARB Should Modify Banking To Include All Compliance Instruments. PG&E recommends that the banking scope be broadened to include all compliance instruments, not just allowances. PG&E suggests that the language be modified to read:

> (a) ~~Allowances~~ Compliance Instruments Issued for a Current or Previous Compliance Period. A CA GHG ~~allowance~~ compliance instrument or a~~n allowance~~ compliance instrument issued by an approved GHG ETS pursuant to subarticle 12 may be held ("banked") by an entity registered pursuant to section 95830. (PGE4)

Response: We did not make the requested change because it is addressed in section 95922(c). Section 95922(a) was included for the specific case of allowances that may be issued by ARB or an approved GHG ETS.

L-19. Comment: MSCG commends ARB Staff for recognizing the need for flexibility in holding limits to accommodate a wide variety of legitimate needs. We believe that the approach devised in the latest proposed regulation strikes a workable balance between not hampering legitimate commercial activities and providing comfort to regulators that there are sufficient safeguards in place against monopolization and market manipulation. However, we offer the following comments in support of suggested language clarification. It is unclear if the holding limits will be applied to each individual vintage within the current compliance period, or against all vintages combined that will be eligible for use in the current compliance period. Will there be separate holding limits for 2013 and 2014 vintages, or a single holding limit for the combined vintages? If the "future" holding limits will be applied to future compliance periods, not individual future vintage years, will there be separate holding limits for the 2015-2017 and 2018-2020 compliance periods in 2012, or will it be a holding limit for all future vintages combined? The formulas in the proposed regulation facilitate the calculation of the applicable holding limits. However, it would be very helpful if there was a chart indicating the "base" holding limits in absolute numbers (recognizing that the ability to carry over banked allowances and other adjustments make creation of a chart for final, adjusted holding limits impossible). (MSCG3)

Response: We modified section 95920(c) to clarify that the holding limit will apply to allowances that can be used for compliance in the current compliance year, separately from those that cannot be used for compliance in the current compliance year. We also modified section 95920(c)(1) to clarify a reference to section 95856(b), which defines the vintages that can be used for current compliance year. Additionally, we modified section 95920(c)(2) to be consistent with section 95856(b), and state that the ability to use allowances changes with each year, not each compliance period. That is, vintage 2015 allowances can be used for surrender for the compliance obligation in 2016, but vintage 2016 and 2017 allowances purchased at the advance auction may not be used for surrender for the compliance obligation in 2016, and together apply toward the holding limit for future vintages.

Holding Limits: Modify Calculation

L-20. Comment: Section 95920(d)(2)(B) Trading, Holding Limit. LADWP seeks clarification in the regulation to ensure that the holding limit is able to account for and accommodate annual fluctuations in emissions associated with electricity consumption. Per ARB's staff report, the purpose of having a holding limit is "to prevent a market participant, or a group of market participants that can coordinate their buying and selling, from gaining too large a share of the goods in a market. The limits are common features in commodity markets." However, the holding limits proposed can present a problem for compliance entities in the case where a previous year's emissions are significantly less than the next year's compliance obligation. For example, if an entity's 2012 emissions were 8 MMT, the limited exemption from the holding limit is 8 MMT after this amount is placed in the entity's compliance account. ARB's staff report states that the limit to the transfer of allowances added to an entity's compliance account is equal to the verified emissions reported for the entity for the previous year. So, for example, if that entity's allocation is 12 MMT, then 4 MMT is in the holding account and only up to 0.271 MMT can be purchased. If that entity projects that it will be short such that more than 0.271 MMT needs to be purchased, then it will likely face violations. (LADWP4)

> **Response:** We are unable to reproduce the calculation of the amount to purchase stated in this comment. The commenter notes that the Staff Report states a limit on transfer of allowances; however, section 95920(d) was completely rewritten in the proposed modifications. Under section 95920(d)(2), the limited exemption from the holding limit is, on June 1, 2012, the most recent verified emissions data report that has received a positive or qualified positive emissions data verification statement. Beginning in 2013, the exemption increases each October 1 by the amount of emissions contained in the most recent emissions data report that has received a positive or qualified positive emissions data verified statement during that year. On December 31 of the calendar year following the end of a compliance period, the limited exemption will be reduced by the sum of the entity's compliance obligation over that compliance period.
>
> In addition, the calculation of the limited exemption reflects the expansion of the program scope in 2015 by having the annual increase reflect the full scope emissions beginning with the report received in 2014.

Holding Limits: Flexibility and Competitiveness Concerns for Covered Entities

L-21. (multiple comments)
Comment: The proposed Regulation's holding limit would further put independent generators at a competitive disadvantage to the utilities they serve, preventing large generators such as Calpine from taking advantage of the flexibility afforded by multi-year compliance periods and only requiring covered entities to surrender 30 percent of their emissions in any year. Calpine suggests that CARB expand the limited exemption so that it would include the entirety of a covered entity's prior year's emissions, without first requiring the allowances to be deposited into the entity's compliance account. Modify section 95920(d)(2)(a) as follows:

> ~~(A)~~ The limited exemption is the number of allowances which are exempt from the holding limit ~~after they are transferred by a covered entity or an opt in covered entity to its compliance account.~~ (CALPINE3)

Comment: The holding limits described in the Regulation are irrespective of a compliance entity's allowance obligation. An entity with a very small allowance obligation is subject to the same absolute holding limit as an entity with a multi-million allowance obligation. The result is restrictive holding limits that represent a small fraction of the allowance obligation of compliance entities with large allowance surrender obligations. Any holding limit must take account of a compliance entity's full compliance period allowance obligation (i.e. not only annual compliance obligation) plus the need to bank and hedge allowances. A holding limit that does not consider compliance obligation and banking/hedging removes important compliance flexibility from those who most need it—i.e. those with large allowance surrender obligations. It is important to understand that the existence of a holding limit does not assure the avoidance of market manipulation, nor does the absence of an arbitrary holding limit allow for market manipulation. The largest carbon market in the world (the EU ETS) operates without an allowance holding limit. We are unaware of any demonstrable manipulation issues in that market. Likewise, other major commodity markets operate with general prohibitions on market manipulation that do not require the imposition of arbitrary or across-the-board holding limits to help detect or enforce. BP recommends against the use of allowance holding limits. The Regulation attempts to address concerns about holding limits by introducing a very limited exemption. However, the holding limit "exemption" is not really an exemption at all as in order to qualify for the "exemption," allowances have to be deposited in a compliance account from which they cannot be removed. If a very limited exemption is as far as the Regulation will go to address these concerns about holding limits, then it must be an actual exemption from the holding limit—which means the allowances subject to the exemption can reside in the holding account. Modify section 95920(d)(2)(A) as follows:

(A) The limited exemption is the number of allowances which are exempt from the holding limit calculation after they are transferred by a covered entity or opt-in covered entity to its holding ~~compliance~~ account….

The Regulation introduces the concept of compliance accounts as an apparent means to mitigate the effect of the very low holding limits. It appears that once an allowance is deposited in this account, it cannot be removed for trading or future use. These allowances would thus be removed from the market, unable to flow freely to provide market liquidity and confidence. For entities with large allowance surrender obligations, this essentially removes any flexibility from a multi-year compliance period and results in a real-time allowance surrender obligation. (BP2)

Comment: The modified regulation limits the number of allowances a regulated entity can hold in any given year, and the limits are essentially identical for all covered entities. Given the variation in the sizes of covered entities' compliance obligation, setting the holding limit at the same level for all entities is inappropriate. An entity with low emissions would potentially be able to hold sufficient allowances to cover their compliance obligations for multiple years, while an entity with high emissions may not be able to hold sufficient allowances to cover even a single year. The holding limit would thus greatly restrict the ability of larger entities to manage their compliance. The provision that exempts allowances in the compliance account up to the level of accrued emissions is not sufficient to address this problem because it would require annual retirement of allowances in order to stay under the holding limits, which undermines the intended flexibility of the three-year compliance interval. Rather than set the holding limit at the same level for all entities, the holding limit for covered entities should be set relative to each entity's most recent emissions data report, and all allowances in the compliance account and any allowances banked from previous periods should be exempted from the holding limit. This would ensure that each entity has sufficient flexibility to manage its compliance obligation over time. For voluntary associated entities, the holding limit shall be calculated as outlined in section 95920(d). Modify section 95920 as follows:

(d) The holding limit ~~will be calculated~~ for allowances qualifying pursuant to section 95920(c)(1) will be calculated as

(1) for covered entities, the amount of emissions contained in the most recent emissions data report that has received a positive or qualified positive emissions data verified statement during the year ~~sum of:~~

(~~1~~2) for voluntary associated entities, ~~T~~the number given by the following formula:

Holding Limit = 0.1*Base + 0.025*(Annual Allowance Budget – Base)

In which:

"Base" equals 25 million metric tons of CO_2e.

"Annual Allowance Budget" is the number of allowances issued for the current budget year.

(~~2~~3) A Limited Exemption from the Holding Limit is calculated as:

(A) The limited exemption is the number of allowances which are exempt from the holding limit calculation after they are transferred by a covered entity or an opt-in covered entity to its compliance account.

~~(B) On June 1, 2012 the limited exemption will equal the annual emissions most recent emissions data report that has received a positive or qualified positive emissions data verification statement.~~

~~(C) Beginning in 2013 on October 1 of each year the limited exemption will be increased by the amount of emissions contained in the most recent emissions data report that has received a positive or qualified positive emissions data verified statement during that year.~~

~~(D) If for any year ARB has assigned emissions to an entity in the absence of a positive or qualified positive emissions data verification statement the calculation of the limited exemption will use the assigned emissions.~~

~~(E) For the first compliance period all reported emissions or assigned emissions used to calculate the limited exemption will include only the emissions associated with the scope for the program during the first compliance period.~~

~~(F) Beginning in 2015, all reported emissions or assigned emissions used to calculate the limited exemption will include the~~

~~emissions associated with the change in scope taking place in 2015.~~
~~(G) On January 1, 2015 the limited exemption will be increased by the amount of emissions included in the emissions data report received during 2014 but not yet included in the limited exemption pursuant to section 95920(d)(2)(E).~~
~~(H) On December 31 of the calendar year following the end of a compliance period, the limited exemption will be reduced by the sum of the entity's compliance obligation over that compliance period.~~ (WPTF2)

Comment: PG&E is concerned that the existing holding limit prevents entities with a large compliance obligation from being able to sufficiently physically hedge future obligations and is unnecessarily high for entities that lack any compliance obligation. PG&E believes the holding limit should be established as 100 percent of each entity's most recent verified emissions plus a fixed holding limit quantity. PG&E recommends that the formula for calculating the holding limit for current compliance allowances be adjusted downward, as the holding limit is unnecessarily high for entities with little or no compliance obligation. Further, all allowances transferred to an entity's compliance account should be exempt from the holding limit. Entities should be able to designate at the time of bid submission whether any purchased allowances should be placed directly into a buyer's compliance account, bypassing their holding account. If so, then those allowances should also be exempt from the holding limit and the holding limit constraint associated with bidding into the auction per section 95911(d)(3)(B). PG&E recommends ARB clarify that the limited exemptions specified in Section 95920(d)(2)(B) and (C) represent a cap on the number of allowances that will be exempted from the holding limit. PG&E also recommends ARB clarify that on June 1, 2012, this cap will equal the annual emissions contained in the most recent emissions data report. In addition, as stated above, PG&E recommends that all allowances transferred to an entity's compliance account be exempt from the holding limit. Modify sections 95920(b)(2), 95920(d)(1), 95920(d)(2), and 95920(e) as follows:

(2) The holding limit calculation will not include allowances contained in limited use holding accounts or compliance accounts created pursuant to section 95831.

(1) The number given by the following formula:

Holding Limit = 0.017 ~~0.01~~*Base + 0.00417 ~~0.025~~* (Annual Allowance Budget – Base)

In which:

"Base" equals 25 million metric tons of CO_2e.
"Annual Allowance Budget" is the number of allowances issued for the current budget year.

(2) A Limited Exemption from the Holding Limit is calculated as:

(A) The limited exemption is the number of allowances which are exempt from the holding limit calculation ~~after they are transferred by a covered entity or an opt-in covered entity to its compliance account~~.

(B) On June 1, 2012 the limited exemption cap will equal the annual emissions contained in the most recent emissions data report that has received a positive or qualified positive emissions data verification statement.

(C) Beginning in 2013 on October 1 of each year the limited exemption cap will be increased by the amount of emissions contained in the most recent emissions data report that has received a positive or qualified positive emissions data verified statement during that year.

(e) The holding limit will be calculated for allowances qualifying pursuant to section 95920(c)(2) as the number given by the following formula:

Holding Limit = 0.017 ~~0.01~~*Base + 0.00417 ~~0.025~~*(Compliance Period Budget – Base)

In which:

“Base” equals 75 million metric tons of CO_2e.

“Compliance Period Budget” is the number of allowances issued for the future compliance period from which the allowances were sold at the advance auction. (PGE4)

Comment: Barclays strongly believes that holding limits, in their current and proposed form, should be excluded from the proposed rules. Holding limits, as currently proposed, will serve to decrease liquidity and compromise market efficiency while increasing the costs of risk management. Ultimately, this will pass increased costs along to the consumer. For example, if covered entities are in danger of breaching their holding limits, they may be forced to either transfer excess allowances into their compliance accounts, or to sell their allowances into the market at a time and at a price which may not conform to approve hedging programs. Transferring allowances into a covered entity’s compliance account precludes further trading of those allowances, thereby taking them out of the system. Although such allowances would eventually have been retired for compliance and removed from the system, holding limits require that they be removed from the system earlier than necessary. Holding limits undermine the system’s intended banking benefits. Banking is included in most emissions trading systems to provide cost containment and to allow hedging programs to smooth compliance pricing out over several periods. Holding limits undermine the intended purpose of the banking provisions of the Cap and Trade rule by removing the flexibility provided by banking guidelines. Ultimately, the increased risk and decreased liquidity associated with holding limits will deter the growth of this nascent market. This will increase the cost of compliance with the Cap and Trade Program, which will eventually lead to increased costs to California energy consumers. (BARCLAYS)

Comment: The Compliance Account Exemption – Mitigation of costs: Under the compliance account exemption, allowances deposited in a covered entity's compliance account will not count towards such covered entity's holding limit. The compliance account exemption, however, fails to adequately mitigate the increased costs resulting from the holding limit rule that are imposed on covered entities with compliance obligations in excess of the holding limit. Compliance Obligations: The compliance account exemption does not address a fundamental inconsistency in the application of the holding limit rule that relates to covered entities. Covered versus non-covered: All allowances held by the covered entities, including those needed to satisfy their compliance obligations, count toward the limit under the holding limit rules. Nothing in the compliance account exemption addresses this disparate treatment between covered entities and non-covered entities, and consequently, non-covered entities continue to enjoy more flexibility and discretion then covered entities. In our view, the most appropriate manner to address the increased costs and added burdens imposed on covered entities by the holding limit is to exclude from the holding limit the number of allowances needed by covered entities to satisfy their compliance obligations. In other words, a covered entity holding the number of allowances equal to its compliance obligation should be treated no differently for holding limit purposes than a non-covered entity that is not holding any allowances. (CHEVRON3)

Comment: The holding limit should account for differences between covered and non-covered entities. The holding limit rule does not account for material differences in the behavior and interests of covered entities and non-covered entities. Whereas the primary objective of covered entities is to purchase sufficient allowances to satisfy their compliance obligation, the objective of non-covered entities is to purchase allowances and subsequently sell them at a higher price. By treating both covered and non-covered entities the same, the holding limit rule does not take into account the fact that a covered entity must retain most, if not all, of the allowances it acquires in order to fulfill its compliance obligations. Therefore, if it is determined that holding limits must be implemented, such holding limits should only apply to the number of allowances in excess of a particular covered entity's compliance obligation. A covered entity holding the number of allowances equal to its compliance obligation should be treated no differently for holding limits purposes than a non-covered entity that is not holding any allowance. Otherwise a key policy objective for imposing holding limits (i.e., limiting market manipulation) will be undermined as non-covered entities will be given an advantage over all other participants. (CHEVRON3)

Comment: The holding limit is too low. As currently written, significant amounts of allowances, for large compliance entities will be locked in compliance accounts. This creates an uneven playing field that favors traders over regulated entities. Compliance entities must be able to hold and trade a larger portion of their allowances to adequately manage their risk throughout the Cap and Trade program. CCEEB recommends that the program allow compliance entities to hold sufficient allowances to cover their obligation for the entire compliance period based on a rolling three year emissions obligation. This change would free up allowances for the major compliance entities and enable a much more liquid market where an entity could adequately hedge its forward risk without major complications. While there are still allowances locked in compliance accounts in some years, the increase in holding limits makes these limitations much more manageable. (CCEEB3)

Comment: The Holding limit on allowances should be modified to reflect individual Covered Entities compliance obligations. IEP shares CARB's concerns regarding hoarding, market manipulation, etc., there needs to be a mechanism in place to address the compliance needs of large obligated entities where the current holding limit potentially creates discriminatory impacts, with respect to flexible compliance instruments. In order to compensate for these disparate impacts on obligated entities, CARB should adjust the holding limit calculation for large obligated entities to reflect the different magnitudes of compliance obligations among obligated entities. Specifically, upon an application by a covered entity, CARB may determine that the established Holding Limits disadvantage the covered entity unreasonably, and CARB may establish a unique holding limit for that covered entity scaled to the appropriate magnitude of the covered entity's compliance obligation. (IEPA2)

> **Response:** As structured, the holding limits have two components: a quantity determined by the formula in section 95920(d)(1), and a limited exemption for compliance entities described in section 95920(d)(2). The quantity determined by formula applies uniformly to allowances held in holding accounts for compliance and non-compliance entities alike. The quantity of the limited exemption for entities with a compliance obligation is unique to each entity, based on that entity's reported emissions from previous years, as described in section 95920(d)(2). The limited exemption applies only to allowances within an entity's compliance account. Allowances in a compliance account may not be removed from that account except for transfers by the Executive Officer to the Retirement Account.
>
> Commenters argue that this structure has several consequences. To summarize, the main contentions are: (1) That the limits reduce compliance flexibility, including the benefits of three-year compliance periods, (2) that the limits reduce trading/hedging flexibility, (3) that the limits' restrictions on trading/hedging flexibility are unequal for entities with compliance obligations of varying sizes, and particularly restrict entities with large compliance obligations, and (4) that limiting the exemption for compliance entities to allowances in compliance accounts reduces market liquidity.
>
> To remedy these consequences, commenters propose various ways to allow compliance entities to hold more allowances in their holding accounts. We disagree with these recommendations.

As stated in the Staff Report, the purpose of a holding limit is to prevent a market participant, or a group of market participants that can coordinate their buying and selling, from gaining too large a share of the goods in a market. The size of the limit, coupled with the limited exemption, represents a trade-off between having a limit that is small enough to reduce opportunities for market manipulation and a limit that is so small that it reduces banking and market liquidity by restricting the activity of non-covered entities.

We agree that the holding limits could have the consequence of minor reductions in trading flexibility. However, we do not believe that this consequence will be severe. The holding limit calculation would allow all covered entities to keep about 6 million MT of allowances, along with an unlimited amount of offsets, in their holding accounts during the first compliance period. This number rises to over 11 million MT in the second compliance period. Allowances kept in the holding account may be traded. These levels should give covered entities the opportunity to make profitable sales when they are able to identify short-term price increases. Many covered entities have informed us that they will procure as close in time as they emit, so the actual effect of the limit on market liquidity cannot be predicted. Overall, we believe we have struck the proper balance between promoting market flexibility and preventing market abuse.

The holding limits as structured provide equivalent treatment for compliance and voluntarily associated entities. All types of entities may hold up to the same quantity of allowances for trading, hedging, banking, and other speculative behavior. Compliance entities may also hold, in their compliance accounts, the allowances needed to comply. To allow compliance entities larger exemptions for the purpose of speculative behavior would undermine both the uniform application of the holding limit to all entities and the prevention of dangerous levels of concentration in the holding of allowances. Lowering the holding limit for voluntarily associated entities would similarly favor speculative behavior by compliance entities. We do not believe either approach recommended in the comments is appropriate.

The multi-year compliance periods and the annual compliance obligation of 30 percent of the previous year's emissions are design features of the cap-and-trade program that provide temporal flexibility in compliance with the surrender obligation. Other features of the program, including the very use of cap-and-trade as a measure, give entities a great deal of flexibility in how and when to reduce emissions. Entities are free to move allowances to their compliance account at any time before the compliance deadline, a fact that is unchanged by the holding limit.

Beyond the requirement to surrender instruments on a compliance date, entities may choose to engage in any of a wide variety of strategies to trade allowances (including buying, selling, and holding) and hedge risk. We believe options for trading to implement a strategy will include bilateral transactions, transactions through an intermediary, and exchange transactions in both spot and derivatives markets, as well as auctions. One strategy implied in the comments is to accumulate a number of instruments equal to an entity's compliance obligation in a holding account, and to move those instruments into the compliance account at the compliance deadline. We agree that this particular trading strategy, and perhaps others, may be restricted by the holding limit for the entities with the largest compliance obligations. However, we believe that entities have sufficient remaining trading flexibility, and that the regulatory language implements the correct tradeoff between flexibility and managing the risk of manipulation.

Since allowances in a compliance account may not be removed except for retirement, they cannot be traded by the entity that holds them. We agree that this has the potential to reduce market liquidity. However, we believe the effect is not large, because risk-averse firms acquiring allowances for compliance (as opposed to speculative purposes) will generally not make those allowances available to the market; the available supply is not likely to be much different even if the allowances are not in compliance accounts. Second, the concentration of allowances among a few large traders could also reduce liquidity, and this is a potential outcome of removing the holding limits. We believe that the net effect on liquidity cannot be predicted.

For the reasons above, we do not agree with the proposed changes to section 95920.

L-22. Comment: SCE is very concerned about the small size of the Holding Limits relative to SCE's total annual GHG price exposure. This substantial difference will make it extremely difficult to effectively hedge SCE customers' exposure to fluctuating GHG prices. In addition, SCE has a relatively low direct compliance obligation (for which it must retire compliance instruments) relative to its contractual obligations and electricity market price exposures (which are both financial exposures rather than compliance obligations). As such, SCE cannot mitigate its GHG price exposure by simply transferring compliance instruments into its Compliance Account and thereby take advantage of the Limited Exemption laid out in section 95920(d)(2)(A)(H) to avoid approaching its Holding Limit. Accordingly, SCE proposes ARB revise the Holding Limit calculation to be the greater of the current formula contained in the July 2011 Proposed Modifications or a compliance entity's allowance allocation for that same year. This modification would allow SCE and other similarly situated compliance entities with large GHG price exposures to more effectively manage their exposure, but would also avoid market manipulation concerns that might arise through more general Holding Limit increases. Modify section 95920(d)(1) as follows:

(1) The number given by the following formula:

Holding Limit = <u>the greater of</u>

<u>1)</u> 0.1*Base + 0.025*(Annual Allowance Budget – Base)

In which:
"Base" equals 25 million metric tons of CO_2e, or

2) an individual utility's allowance allocation for that same year as defined in Table 9-3. (SCE3)

Response: We do not agree with the commenter's assertion that SCE cannot hedge its customers' exposure to fluctuating GHG prices. First, SCE can cover its direct emissions through transfers to its compliance account. For the first compliance period, SCE could hold up to about 6 million MT of allowances, plus offsets, in its holding account. In the second compliance period this increases to over 11 million MT. SCE could acquire and hold allowances under its holding limit for transfer to generators if that is how SCE resolves its exposure for purchase entity. Second, we modified section 95834, which governs beneficial holdings. This is a voluntary path by which a principal and agent could both agree to have the agent hold allowances for later transfer to the principal. Using this approach, allowances held by SCE would not count against its holding limit.

L-23. Comment: Holding limits are difficult to effectively enforce and can actually impede the proper functioning of a Cap and Trade program, particularly in the early years of the program when liquidity is most needed. The position limit contained in the modified Cap and Trade Regulations is unprecedented and does not exist in any other major carbon or commodities market. The limit is actually a rule developed by the Commodities Futures Trading Commission for the purpose of limiting financial exposure in futures commodities markets. IETA is concerned that ARB's proposal to extend a rule designed to regulate futures markets to regulate spot (i.e., inventory) markets is both untested and unsupported by the record. IETA is pleased to see the addition of a holding limits exemption, detailed in section 95920(d)(2). This exemption seems to permit covered entities to hold in their compliance account allowances in excess of the position limit, if such allowances are necessary to meet a compliance obligation. There are a number of issues with the proposed rules. First, as allowances in compliance accounts cannot be withdrawn by their account holders, the rule will result in a number of allowances being taken out of the market early. This will reduce liquidity and increase the ability of any player to manipulate markets. Second, the rule treats large covered entities unfairly by requiring them to comply earlier than their smaller competitors. Such covered entities with large compliance obligations will also be forced to consistently purchase a sufficient amount of allowances per auction, regardless of market conditions, at each auction for placement in their compliance accounts and will be unable to trade these allowances when market conditions improve. This also prevents entities from engaging in hedging strategies that might ultimately save ratepayers money. Based on the foregoing, IETA recommends that holding limits be discarded or, in the alternative, holding limits be adjusted to permit large covered entities to hold a quantity of allowances equal to the greater of (1) the holding limits currently proposed in section 95920 or (2) a quantity equal to that covered entity's compliance obligation. (IETA3, BARCLAYS)

Response: First, the comment is not correct in its assertion that the holding limit was developed by the CFTC to regulate futures markets. The holding limit was developed in consultation with Jeffrey Harris, who was formerly employed at the CFTC. His recommendations were specific to the carbon market being developed by California and the other WCI jurisdictions.

Second, members of the EU ETS did not conclude that auction frequency alone can control the risk of market manipulation. They have other procedures, analogous to "responsibility levels" in U.S. commodity markets, which are part of EU national programs. Consideration of position and purchase limits are not unprecedented. The EU ETS members have identified position and purchase limits as backstops which could be introduced as needed in case anti-competitive conditions emerge.

Third, we believe the commenter overstates the effect of the limited exemption on market liquidity by assuming that a covered entity will be willing to trade away all of its accumulated allowances. Based on our conversations with stakeholders, we expect that most covered entities will be prudent and not accumulate allowances in much smaller numbers than their cumulative emissions obligations. Thus, even if we had no holding limit, the number of allowances held would overstate the number that could be expected to enter the market at any point because most will be "committed" to compliance needs.

Fourth, all registered entities can keep in their holding accounts up to about 6 million MT of allowances in the first compliance period and about 11 million MT in the second compliance period, all of which will be available for trading. The comment does not explain why this is not sufficient to provide market liquidity.

Finally, the holding limit does not force large covered entities to buy uniform amounts at the auction. Revised section 95912(k)(3) allows the transfer of allowances purchased at auction directly to an entity's compliance account, so the amount purchased at each auction is not restricted by the amount that can be placed directly into a holding account.

Registration and Accounts

L-24. Comment: Section 95921(e)(3) does not exist. This is an incorrect cross reference. It appears both (B) and (C) are referring to the same consignment allowances from EDUs per section 95831(a)(3). Modify section 95831(b)(2) as follows:

> (2) A holding account to be known as the Auction Holding Account into which allowances are transferred to be sold at auction from:
>
> (A) The Allocation Holding Account;
>
> (B) The holding accounts of those entities for which allowances are being auctioned on consignment pursuant to section 95831(a)(3) ~~95921(e)(3);~~ and

(C) The limited use holding accounts of those entities consigning (allowances to auction pursuant to section 95910 subarticle 8. (LADWP4)

Response: We agree that the cross-reference was incorrect. In the second 15-day changes to the regulation, the cross-reference was corrected to read section 95921(f)(3).

L-25. Comment: Section 95830 proposes to reduce the registration period with ARB from 45 calendar days to 30 calendar days because ARB believes this provides enough time to submit all the information needed to register. The registration time frame should remain at 45 calendar days since the program is new and unproven, and internal company reviews could take longer than the proposed 30 calendar days to ensure the accuracy and completeness of submittals. (VALERO2)

Response: We believe that the 30 calendar days specified in section 95830(d)(1), Registration Deadlines, is sufficient time to register, given that the requirement applies to entities that are not covered entities as of January 1, 2013. That date is one year after the initial registration, so entities that are covered under the MRR will have adequate time to determine when they have to register.

Authorized Account Representatives/Attestation

L-26. Comment: GreenX requests ARB exempt exchange clearing holding accounts from the limit on a single authorized account representative and an alternate authorized account representative (section 95832). The purpose of such a change is to support efficient delivery of exchange traded allowances. Permitting only two account representatives for clearinghouse accounts could significantly delay the transfer of cleared contracts, making the market less efficient. To facilitate timeline and accurate deliveries, the clearinghouse will often dedicate the entire Deliveries Team (5-10 staff members) to the process. By allowing up to ten users access to the exchange clearing holding account, these risks will be mitigated. Modify section 95832 as follows:

<u>(i) For exchange clearing trading accounts, the authorized representative may designate up to ten delivery analysts responsible for the account to directly access the account and assist in performing the functions of an entity meeting the requirements of 95814(a)(3) and making submissions pursuant to 95832(h).</u> (GREENX)

Response: Although account holders must designate one authorized account representative and one alternate authorized account representative, the authorized account representative or alternate authorized account representative may delegate, to one or more natural persons, his or her authority to make an electronic submission (section 95832(h)). This existing provision accommodates multiple users of an account. Therefore, we do not agree that a modification of section 95832(y) is necessary.

L-27. (multiple comments)
Comment: Section 95832(a) sets forth the regulations pursuant to which a covered entity establishes personnel to serve as the Authorized Account Representative. As part of these regulations, individuals who are tasked with serving as their company's Authorized Account Representative are required to "certify that I have all the necessary authority to carry out the duties and responsibilities contained in title 17, article 5, sections 95800 et seq. on behalf of such persons and that each such person shall be fully bound by my representations, actions, inactions, or submissions and by any order or decision issued to me by the accounts administrator or a court regarding the account;" (page A-63). This certification is overly broad and should not be required for an entity to serve as its company's Authorized Account Representative. (WPTF2)

Comment: Sections 95832(a) and (d) require the Authorized Account Representative to attest that all the information submitted by the Authorized Account Representative is true, accurate and complete. Typically, such attestations would state that any such statements are "to the best of my knowledge and belief true, accurate, and complete." This language was contained in the earlier version of section 95832(d) of the regulation, but has been deleted from the modified regulation. Removal of this language creates a burden for the Authorized Account Representative that goes beyond what is typical for such attestations, and WPTF believes that the deleted language should be re-instated into the modified regulation. Modify sections 95832(a)(4)-(6) and (d) as follows:

> (4) The authorized account representative and any alternate authorized account representative must attest, in writing, to ARB as follows: "I certify ~~under penalty of perjury under the laws of the State of California~~ that I was selected as the authorized account representative or the alternate authorized account representative, as applicable, ~~by an agreement that is binding on all persons~~ <u>for entities</u> who have an ownership interest with respect to compliance instruments held in the account. I certify that I have all the necessary authority to carry out the duties and responsibilities <u>of an authorized account representative, as specified</u> in title 17, article 5, sections 95800 et seq., on behalf of such entities. ~~persons and that each such person shall be fully bound by my representations, actions, inactions, or submissions and by any order or decision issued to me by the accounts administrator or a court regarding the account;~~
> (5) The signature of the authorized account representative and any alternate authorized account representative and the dates signed; and
> (6) An attestation as follows: "I certify that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. I also certify ~~under penalty of perjury of the laws of the State of California~~ that all information required to be submitted to ARB is true, accurate, and complete <u>to the best of my knowledge and belief</u>.
>
> (d) Each submission concerning the account shall be submitted, signed, and attested to by the authorized account representative or any alternate authorized account representative for the entities that own compliance instruments held in

the account. Each such submission shall include the following attestation statement by the authorized account representative or any alternate authorized account representative: "I certify ~~under penalty of perjury under the laws of the State of California~~ that "I am authorized to make this submission on behalf of the entities that own the compliance instruments held in the account. I certify ~~under penalty of perjury of law~~ that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify ~~under penalty of perjury under the laws of the State of California~~ that the statements and information submitted to ARB are true, accurate, and complete to the best of my knowledge and believe. " I consent to the jurisdiction of California and its courts for purposes of enforcement of the laws, rules and regulations pertaining to title 17, article 5, sections 95800 et seq., and I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment." (WPTF2)

Comment: CARB states that inclusion of "under penalty of perjury" is necessary to ensure that all information submitted is true and complete. However, typical EPA and SCAQMD certifications do not include this language. The underline/strikeout language makes this attestation more consistent with SCAQMD language for Title V operating permit certification. The alternate recommendation is for ARB to preserve its previous language. Modify section 95832(a)(4) as follows:

(4) The authorized account representative and any alternate authorized account representative must attest, in writing, to ARB as follows: "I certify ~~under penalty of perjury under the laws of the State of California~~ that I was selected as the authorized account representative or the alternate authorized account representative, as applicable, by an agreement that is binding on all persons who have an ownership interest with respect to compliance instruments held in the account. I certify that l have all the necessary authority to carry out the duties and responsibilities contained in title 17, article 5, sections 95800 et seq. on behalf of such persons and that each such person shall be fully bound by my representations, actions, inactions, or submissions and by any order or decision issued to me by the accounts administrator or a court regarding the account;" (LADWP4)

Comment: The draft regulation requires that any submission is absolutely true, accurate and complete. Submissions will include unverified emissions reports that will undergo verification where errors would be found. This draft also specifically deletes "to the best of my knowledge and belief..." which recognizes that the account representative is limited to his knowledge. There are enforcement provisions that would address violations that warrant higher penalties for misconduct. Modify section 95832(d) as follows:

(d) Each submission concerning the account shall be submitted, signed, and attested to by the authorized account representative or any alternate authorized account representative for the entities that own compliance instruments held in the account. Each such submission shall include the following attestation statement by the authorized account representative or any alternate authorized account representative: "I certify ~~under penalty of perjury under the laws of the State of California~~ that I am authorized to make this submission on behalf of the entities that own the compliance instruments I held in the account. I certify ~~under penalty of perjury~~ that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on information and believe formed after ~~my~~ inquiry of those individuals with primary responsibility for obtaining the information, I certify ~~under penalty of perjury~~ under the laws of the State of California that the statements and information submitted to ARB are to the best of my knowledge and belief true, accurate, and complete. " I consent to the jurisdiction of California and its courts for purposes of enforcement of the laws, rules and regulations pertaining to title 17, article 5, sections 95800 et seq., and I am aware that there are significant penalties for submitting intentionally false statements and information or intentionally omitting required statements and information, including the possibility of fine or imprisonment." (LADWP4)

Comment: The phrase "to the best of my knowledge" must be re-inserted in the attestations below. Although the Utilities understand CARB's concern to ensure the information submitted is accurate, it is unreasonable to require the authorized account representative to become personally liable for any incomplete or inaccurate information that the representative was not aware of after completing his or her due diligence.

Section 95832(a)(6) An attestation as follows "I certify that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. I also certify under penalty of perjury of the laws of the State of California that to the best of my knowledge all information required to be submitted to ARB is true, accurate, and complete."

Section 95832(d) … "I certify under penalty of perjury of the laws of the State of California that the statements and information submitted to ARB are to the best of my knowledge true, accurate, and complete."… (MID3)

Comment: Sections 95832 (a)(6) and (d) provide certification requirements for submittals to ARB. We noticed the deletion of the phrase "to the best of my knowledge" and we believe it is appropriate to include this language as consistent with the certification requirements under the Monitoring and Reporting Rule and the EPA MRR. (UNITEDAIRLINES2)

Comment: In sections 95832(a)(6) and (d), we propose that the language regarding the attestation of the authorized account representative be consistent with the MRR regarding certification, which points to the U.S. EPA Mandatory Reporting of

Greenhouse Gases Rule regarding certification of the GHG emissions report. The EPA reporting rule at section 98.4(e)(1) includes the language, “to the best of my knowledge and belief…” We recommend that this language be added to the end of the sentence in section 95832(a)(6), and reinserted in 95832(d). This will ensure consistency between all three related regulations. (CACC2)

> **Response:** The account representative was always required to sign under penalty of perjury. However, it appears that “to the best of my knowledge and belief” was inadvertently deleted. Unfortunately, we cannot fix this at this time. However, the intent is to hold the Authorized Account Representative to the “best of my knowledge and belief” standard. We will correct this omission when the regulation is amended in the future.

Compliance Accounts

L-28. Comment: Section 95831(a)(4)(B) does not allow compliance instruments to be moved from the compliance account. WSPA believes that the rule must allow compliance instruments within a compliance account to be transferred to another account by the holder. WSPA recommends that this section be amended to allow for compliance instruments within a compliance account to be transferred to another account by the holder. (WSPA3)

> **Response:** We disagree with the suggestion that compliance instruments should be able to be transferred to another account. Compliance accounts from which instruments may not be removed allow for the equal treatment under holding limits of entities with and without compliance obligations. Striking the characteristic that instruments may not be removed would undermine the purpose of the holding limits by allowing entities with large compliance obligations to accumulate and trade a much larger share of the allowances than entities with smaller or no compliance obligation.

L-29. Comment: WPTF suggests that CARB consider the need for separate compliance accounts for each compliance interval. Different compliance accounts would facilitate entities’ tracking and management of compliance across different compliance intervals, and simply the identification of units that are exempt from holding limits. (WPTF2)

> **Response**: We disagree with the suggestion of multiple compliance accounts for each entity, and modified section 95831(a)(1) to clarify that each registered entity will have no more one holding account, compliance account, limited use holding account, or exchange clearing holding account. The tracking function suggested in the comment will be accommodated in the tracking system by the vintage year that is coded into each instrument’s serial number.

L-30. Comment: Accounts under Control of the Executive Officer: Under Auction Holding Accounts, a reference to untimely surrender of allowances in section 95857(d) is needed in section 95831(b)(2). Under Allowance Price Containment Reserve Account, section 95831(b)(4)(c) should be deleted. (WPTF2)

> **Response:** We agree that section 95831(b) needed modification due to changes made in section 95857. We added new section 95831(b)(2)(D) to be consistent with a change in section 95857(d)(1) in the first 15-day changes to the regulation that redirects three of the allowances submitted to fulfill an untimely surrender obligation to the auction holding account. We eliminated existing section 95831(b)(4)(C) due to the revisions to section 95857(d)(1) that redirects three of the allowances submitted to fulfill an untimely surrender obligation to the auction holding account, not to the reserve, as specified in the existing text.

L-31. Comment: Section 95833(a)(2) defines an entity as having a "direct corporate association" with another registered entity when it holds compliance instruments in its own holding account in which another entity has an ownership interest, but it is unclear what is meant by "ownership interest." It would appear that under this section, an electrical distribution utility holding compliance instruments on behalf of another entity in a Beneficial Holding relationship would be considered to have a direct corporate association with the other entity. Section 95833(a)(3) defines "indirect corporate association," but again, it is unclear what is meant by "percentage ownership of the entity in the other entity." PG&E is concerned that if its Beneficial Holding relationships as currently defined by section 95834(a)(2) are considered to be direct corporate associations with ownership interests, it will have to disclose to each of its entities with whom it has such Beneficial Holding relationship the existence of its other Beneficial Holding relationships, in order for those entities to disclose indirect corporate associations in accordance with section 95833(c). PG&E believes that its disclosure of such Beneficial Holding relationships to ARB should be confidential and the disclosure of the relationships should not be shared among the entities with which it has a Beneficial Holding relationship. Further, if such Beneficial Holding relationships are defined as direct corporate associations, PG&E and the entities with which it has Beneficial Holding relationships would be subject to a shared holding limit under section 95920(f) and (g). ARB should resolve this issue by clarifying that an electrical distribution utility's Beneficial Holding relationship as defined in section 95834(a)(2) does not constitute an "ownership interest" as that term is used in section 95833(2)(a). (PGE4)

> **Response:** We agree with the comment and revised sections 95833(a)(2) and (3) to clarify the process and remove all references to the term "ownership interest." Pursuant to section 95834(c), a beneficial holding relationship is not a corporate association unless the entity serving as agent refuses to agree to the information-sharing restrictions contained in section 95834(c)(1).

L-32. (multiple comments)
Comment: Section 95833(a)(1)(D) should be deleted. That section provides that an entity has a "direct corporate association" with another entity if any one of the entities "controls more than 20 percent of the other entity's affairs through some other means."

The phrase “controls more than 20 percent of the other entity’s affairs through some other means” is too vague to have any practical application. How would an entity or the ARB know if that entity controls 20 percent of another entity’s affairs through “some other means”? Section 95833(a)(2) should be deleted. The section provides that an entity has a “direct corporate association” when it holds “allowances in its holding account in which another entity has an ownership interest.” It is unclear what possible ownership interest a second party could have in instruments in a first party’s account, given that:

- The instruments exist only to the extent that they are recorded in an account—they have no independent existence in the way that physical goods do; and
- Section 95820(c) (p. 55) explicitly provides that allowances do not constitute property rights: “A compliance instrument issued by the Executive Officer does not constitute property or a property right.”

The wording of section 95833(a)(2) provides that a corporate association only arises under this provision if an entity has attested that its relationship constitutes a corporate association. It would appear, then, that if an entity does not attest to a corporate association, and section 95833(a)(1) does not apply, that entity will not have a corporate association, making this provision essentially voluntary in nature. Modify section 95833 as follows:

> (a) Entities registered pursuant to section 95830 must disclose direct and indirect corporate associations with other registered entities.
>
> > (1) An entity has a “direct corporate association” with another entity if any one of these entities:
> >
> > > (A) Holds more than 20 percent of any class of listed shares, the right to acquire such shares, or any option to purchase such shares of the other entity;
> > >
> > > (B) Holds or can appoint more than 20 percent of common directors of the other entity; or
> > >
> > > (C) Holds more than 20 percent of the voting power of the other entity.~~; or~~
> > >
> > > ~~(D) Controls more than 20 percent of the other entity’s affairs through some other means.~~
> >
> > ~~(2) An entity has a “direct corporate association” with another registered entity when it holds compliance instruments in its own holding account in which another entity has an ownership interest and the entity has attested to the Executive Officer that its relationships with the other entities constitute a corporate association.~~ (SCPPA6)

Comment: Section 95833. Disclosure of Direct and Indirect Corporate Associations.

(a) Entities registered pursuant to section 95830 must disclose direct and indirect corporate associations with other registered entities.

(1) An entity has a "direct corporate association" with another entity if either one of these en titles:

(A) Holds more than twenty percent of any class of listed shares, the right to acquire such shares, or any option to purchase such shares of the other entity;

(B) Holds or can appoint more than twenty percent of common directors of the other entity;

(C) Holds more than twenty percent of the voting power of the other entity; or

~~(D) Controls more than twenty percent of the other entity's affairs through some other means.~~

LADWP recommends that subparagraph (D) be deleted as the term "through some other means" is too vague. LADWP is a member of the Southern California Public Power Authority and the Intermountain Power Authority. LADWP is a significantly larger utility in comparison to its sister POUs in SCPPA and IPA that will also be registered entities under the Cap-and-Trade program. LADWP seeks clarification from ARB in the regulation that these types of POU associations would not constitute a corporate association, insofar as the POUs each have their own separate governing body and rate setting structure, regardless of their participation in these types of Joint Power Authorities. (LADWP4)

Comment: Direct and Indirect Corporate Relationships. Section 95833(a)(1) describes the disclosure requirements for direct and indirect corporate association with other registered entities. Although this seems to be an improvement from current rule language WSPA believes the language is still unclear. WSPA recommends that ARB engage in further discussions with stakeholders, including WSPA, to further clarify issues for rule amendment in the 2nd 15-Day package of amendments. (WSPA3)

Comment: An element of the Regulation that exacerbates the already troubling holding limits is the language on corporate associations. The language here is very broad and results in associated entities with no practical means to jointly hold or manage allowances, subjected to a joint, unworkably low holding limit. Again, the solution here is to avoid the use of holding limits on compliance entities—or to impose a limit that accounts for full compliance obligation and needed flexibility to bank and hedge. (BP2)

Comment: Section 95833 requires disclosure requirements for direct and indirect corporate associations. The thresholds for requiring disclosure of direct and indirect are quite low. Section 95833(a)(2) reiterates that a direct corporate relationship exists when an entity holds compliance instruments in its "own holding account" in which another entity has an ownership interest with other entities." (WSPA3)

Response: We acknowledge the concern expressed in the comments that the language in section 95833(a)(1)(D) would be difficult to implement, and we removed it in the second 15-day changes to the regulation.

We also agree that the language in section 95833(a)(2) can be further clarified, especially in the use of the term "ownership interest." We also removed that language. The intent of the original language was to address cases in which an entity acquires and holds compliance instruments on behalf of a client entity. We addressed that situation through the new language in section 95834 and section 95921(e)(1) and (2), which deal with beneficial holdings and transfers initiated on behalf of clients.

We also revised section 95833(a)(1) which contains the levels of control that establish whether a corporate association exists. We raised the value of these levels from 20 percent to 50 percent for both direct and indirect corporate associations. We believe this change clarifies when an association exists, as well as the concerns raised by the POUs regarding Joint Power Authorities.

L-33. (multiple comments)
Comment: Section 95834, Disclosure of Beneficial Holding. LADWP seeks clarification on the disclosure of beneficial holdings and would appreciate further discussions with ARB staff regarding how this provision is proposed to be implemented. (LADWP4)

Comment: WSPA believes that section 95834 should be clarified to define the exact meaning of beneficial holding. Is it relating to a trader or is it relative to owners and operations? WSPA recommends that ARB engage in further discussions with stakeholder, including WSPA, to further clarify issues for rule amendment in the second 15-day package of amendments. (WSPA3)

Response: We agree with the comment, and we revised the section in the second 15-day changes to the regulation to clarify several features. First, the section provides a voluntary approach that requires the approval of both parties to a beneficial holdings relationship. Second, we expect most traders and brokers to use section 95921(e)(2) to arrange transfers on behalf of clients.

L-34. Comment: For a small subset of IPPs operating under existing, long-term contracts, currently no viable mechanisms exist within their contract structures to recover the cost of the GHG allowances they are obligated to obtain under the C&T program. This limited set of IPPs and combined-heat and power facilities ("CHP") operate under long term contracts. CARB should amend the section 95834, Disclosure of Beneficial Holding, to require a distribution utility to enter into a beneficial holding relationship to cover the emissions obligation of the IPP generator selling to the utility under an existing long-term contract. IEP proposes the following addition, a new section 95834(a)(4) as follows:

> (4) In the event there is a Long-Term Contract for the sale of electricity at wholesale which: i) does not directly or indirectly provide or refer to GHG costs either explicitly or through a) a CPUC approved contract or, b) a CPUC authorized pricing basis that includes GHG costs; ii) was fully executed before the final approval of AB 32 (September 27, 2006); and, iii) has not been renegotiated as of January 1, 2012 to address GHG costs, then, a beneficial holding relationship is deemed to exist pursuant to section 95834(a)(1)(A) without further action. The electric distribution utility party to the Long-Term Contract shall purchase and hold allowances for the eventual transfer to the other party to the Long-Term Contract for the sole purpose of supplying the second entity with compliance instruments to cover emissions resulting from satisfaction of the Long-Term Contract. (IEPA2)
>
> **Response:** We revised section 95834 in the second 15-day changes to the regulation, in part to provide a voluntary path by which parties to electricity contracts could have flexibility to determine who would be responsible for covering generation emissions, and in part to indicate who would have an ability to hold and transfer compliance instruments for that purpose. At no time did we intend to force a resolution to the issue of how long-term contracts should allocate responsibility for emissions. We believe that is the sole responsibility of the parties to the contracts, and we wrote the regulation to provide flexibility. However, we remain neutral on how the responsibility should be assigned.

L-35. (multiple comments)
Comment: Section 95834(b)(1). WSPA believes that the 10 day registration period seems unreasonably strict. WSPA recommends that this section be amended to allow 30 days for the registration period. (WSPA3)

Comment: In general, PPG believes that several of the limitations in the proposed modifications to the cap-and-trade regulation are unnecessarily restrictive. For example, the time limits on certain disclosure and registration requirements in Sections 95830(f) and 95834(b) are unnecessarily short. It should be sufficient that such information be updated by the deadline for the reporting or registration event for which the information is needed. (PPGI)

> **Response:** We disagree with the commenter’s assertion that the information needs only to be updated in time for a reporting or registration event. The information in both sections cited by the comment is used for other purposes. The information collected pursuant to section 95830(f) is needed for market monitoring and to conduct auctions. When an entity updates this information, we will have to analyze the information and update a number of records. Market monitoring is an ongoing process. For the auctions, this updating must be done well before the auction deadlines so that we can analyze the auction application information on the auction’s rather short timelines. The timeline for section

95834(b) is short because we need the information to process any transfers subject to the beneficial holdings arrangements. Longer timelines run the risk of us erroneously flagging transfers as violations.

L-36. Comment: ARB should clarify its requirement that compliance instruments be "earmarked" for a specific principal at the time of purchase. This requirement would limit the usefulness to SCE of entering into a beneficial holding relationship. SCE's *pro forma* and existing contractual language provides SCE with the option of using financial means to settle its GHG obligations to dispatching generators, and this provision would restrict that valuable flexibility. In addition, this pre-procurement earmarking will effectively require agents to predict how many compliance instruments they will want to transfer to their principals. This will lead to speculation, which could result in over-procurement of allowances by compliance entities for their principals, which in turn could raise allowance prices and tie up the market if allowances are no longer unavailable for long-term transfer. ARB should revise section 95834(b) to require the agent to disclose only the transfer of compliance instruments from an agent's Beneficial Holding Account to the Holding Account of the principal. Agents should be able to respond to defined needs from their principals and disclose this information after the fact. (SCE3)

Response: We added section 95834 to provide a voluntary path by which an agent could accumulate allowances for eventual transfer to a principal while counting the allowances against the principal's holding limit. The requirement that the principal confirm the transactions is needed to ensure that it is voluntary. If the agent could act unilaterally, then it could hold more than the principal anticipated, potentially leading to holding limit violations.

We agree that the approach cannot solve all the complexities inherent in electricity contracts. However, the commenter is not correct in asserting that the procedure would restrict the flexibility that utilities need to settle their obligations, for two reasons. First, the utilities have enough room under the holding limit and limited exemption to accumulate more than their direct emissions obligation. Second, any obligation that the utilities take on resulting from contracts for generation are taken on voluntarily, through contract negotiation. Accumulation for eventual transfer can be handled within the holding limit. As the comment states, utilities have options of financial settlement as well. The provisions of section 95834 do not interfere with these options.

The comment is incorrect in its assertion that the provisions would result in over-procurement. This is not logical. Because the principal and agent must both agree to the transactions, the procedure cannot be implemented until there is agreement on how many allowances must be transferred.

Finally, it is not clear why denying the principal the ability to approve transfers under a beneficial holding arrangement would help define their compliance needs as the comment asserts. Allowing the principal to be informed and confirm transfers would seem to be the best way of meeting their needs.

Outside the Scope of the 15-Day Changes to the Regulation

Oversight

L-37. Comment: To safeguard the market and limit individual instances of market manipulation, we recommend that the ARB rely on existing Commodity Future Trading Commission (CFTC) and designated contract market (DSM) rules and their oversight of the commodity markets. (BARCLAYS)

> **Response:** This comment is not suggesting any edits to the regulation. As part of program implementation, ARB will be coordinating with the CFTC to ensure there is oversight of the market program.

L-38. Comment: Cap and Trade Systems Are Difficult to Regulate; Open to Fraud and Manipulation. As the Legislative Analyst's Office (LAO) has found, the State of California lacks authority to effectively regulate markets arising from a cap and trade system. The LAO stated, "ARB has no experience in regulating [trading of compliance instruments in the spot market], and its lack of technical expertise and institutional knowledge of such matters increases the chance that market manipulation could go undetected, in spite of any monitoring efforts that it puts in place." The U.S. Commodity Futures Trading Corporation has not developed carbon spot market regulations. In the words of a 2011 CFTC report, "No set of laws currently exist that apply a comprehensive regulatory regime—such as that which exists for derivatives—specifically to secondary market trading of carbon allowances and offsets. Thus, for the most part, absent specific action by Congress, a secondary market for carbon allowances and offsets may operate outside the routine oversight of any market regulator." ARB's current rulemaking includes general provisions prohibiting fraud, manipulation and gaming but has provided very little detail in way of enhancing carbon market oversight. For example, ARB should include detailed provisions for preventing insider trading, which is a particular risk for carbon markets. ARB should also set rules to deter excessive speculation, such as setting higher position limits, barring financial speculators from bidding in auctions, and prohibiting long-only passive investment in carbon. (FRIENDSOFEARTH2)

> **Response:** No changes were made to the regulation based on the comments. The program already includes provisions to prevent the accumulation of market power by the market participants. CFTC is currently working to finalize its rules, and ARB has been in discussion with their staff to coordinate on market oversight.

L-39. Comment: ARB should use the program delay to reconsider provisions not covered in this rulemaking—like trade exposure and including fuels in the cap—that will create economic burdens and competitive disadvantage in the second compliance period. While trade exposure is not being discussed at this point, it is critical for ARB to review trade exposure for refining as part of its cap and trade program monitoring. Trade Exposure for Refineries and Fuels under the Cap should be evaluated at least one year prior to the start of the second compliance period to prevent adverse effects of the program on California industry, jobs, and the economy. (CHEVRON3)

> **Response:** No changes were made to the regulation based on the comments. Board Resolution 11-32 directs the Executive Officer to continue to evaluate trade exposure for the capped entities and propose amendments, as appropriate.

L-40. Comment: Registration will be required by January 1, 2012 or within 30 days of effective date of the rule. In order for this provision to become effective, the tools and system requirements must be provided sufficiently ahead of time for compliance to occur. WSPA believes a specific date should be deleted from section 95830(d)(1)(B), and the section amended to require registration when ARB publishes appropriate tools and provides a 30 day notice to registrants. (WSPA3)

> **Response:** These comments were previously submitted and responded to under the 45-day changes to the regulation, and fall outside the scope of the first 15-day changes to the regulation. No further response is required.

L-41. (multiple comments)
Comment: The Regulation should specify the authority and responsibilities of a market monitor to include: auction certification, quarterly auction reporting and reports on overall market status. (PGE4)

Comment: We have no recommended changes to section 95921, but would note that the requirements for transactions could and should be built into the functionality of the market tracking system. For instance, the requirement in subparagraph (a)(1)(A) that both parties to a transaction must report the transaction to the accounts administrator within three calendar days can be operationalized within the tracking system by requiring the accounts representative of both parties to authorize the transfer of units between holding accounts. Similarly, the information requirements in subparagraph (c) should be integrated into electronic transaction requests within the tracking system. (WPTF2)

> **Response:** These comments fall outside the scope of the first 15-day changes to the regulation. We have initiated activities to develop the necessary rule implementation infrastructure for the regulation, including a market tracking program to trade allowances; contracts for an auction services provider; and a financial services provider. We are also committed to providing continual public updates, with opportunity for stakeholder comment, on the implementation of the regulation. Because the comments fall outside the scope of the first 15-day changes to the regulation, no further response is required.

Holding Limits

L-42. Comment: Generally, physical commodity markets are not subject to holding limits. Although the CFTC and DCMs impose position limits and position accountability levels on futures contracts, physical positions are not so limited. Even with respect to future contracts, entities are exempt from such limits to the extent they are engaged in "bona fide hedging transactions." This exclusion to the CFTC and DCMs' position limits has existed since 1936 and covers "various balance sheet and trading strategies that are risk reducing." Accordingly, even under the CFTC and DCM rules, an entity can pursue risk reducing hedging strategies that breach position limits. We see no reason that allowances should be treated differently from any other commodity. Similar to other commodities, regulated entities should be able to trade allowances in the physical market without holding limits. Even if the Board does not adopt this view, it should not drive against over 75 years of history that exempts bona fide hedges from trading limits and should adopt a similar exclusion to the proposed rules' holding limits. Furthermore, the CFTC will be able to indirectly exercise anti-manipulation jurisdiction over the physical allowance market. The CFTC may regulate physical markets that relate to and affect a futures market. Because allowances will be listed on an exchange, the CFTC will be able to regulate and punish market manipulation of physical allowances. The Board should not intrude on the CFTC's jurisdiction by imposing holding limits, and should instead rely on the CFTC and the exchanges' expertise and experience in this area. (BARCLAYS)

> **Response:** The comment is not correct in its portrayal of the enforcement actions of the CFTC. While the CFTC can obtain information on spot markets for which there is contract instrument under its jurisdiction, the CFTC only does this when a disruption in the spot market leads to disruption on a designated contract market. The CFTC does not have general enforcement power over spot markets and does not expend monitoring or enforcement resources on these markets. We have explored cooperation with the CFTC, and we will actively share information where it is appropriate.
>
> We are very mindful of CFTC authorities. There is no intrusion on the CFTC's jurisdiction because we are not placing requirements on designated contract markets. Since we are not regulating those markets, we are not restricting covered entities' hedging opportunities.

Registration and Accounts

L-43. Comment: Section 95830 details the registration process for the entities including the information that must be submitted and the deadlines for submittal. Subsection (e) defines that registration is complete when the EO approves the registration and notifies the entity. There is no timeline for EO approval. Modify section 95830(e) as follows:

> (e) Completion of Registration. Registration is completed when the Executive Officer approves the registration and informs the entity and the accounts

administrator of the approval. <u>The executive officer shall approve or deny a registration application within 30 days of submittal.</u> (CCEEB3, PGE4, WSPA3)

Response: This comment falls outside the scope of the first 15-day changes to the regulation. We did not change the language of section 95830(e) from the initially proposed regulatory language, and therefore it was not subject to comment under the first 15-day changes to the regulation. No further response is required.

L-44. (multiple comments)
Comment: Section 95832(f)(4) allows only 1 day to submit a revision of “any change in the entities that own compliance instruments in the account”. PG&E proposes that the time requirement be changed to a minimum of five business days. A small increase in the number of days will help alleviate the challenge of submitting a revision in the situation when “any change” is made on a Friday or a day prior to a California State Holiday, while still ensuring that entities provide the ARB with prompt notice of change. (PGE4)

Comment: Section 95832(f)(4) requires that an entity submit any changes to the account within one day of the change. WSPA believes that one day is simply infeasible for submittal of a revision even with electronic recordkeeping. WSPA recommends that this section be amended to allow 10 days for submittal of changes. (WSPA3)

Response: These comments fall outside the scope of the first 15-day changes to the regulation. We did not change the language requiring that an entity submit an revision “within one day following any change in the entities that own compliance instruments in the account” from the initially proposed regulatory language, and therefore it was not subject to public comment under the first 15-day changes to the regulation. No further response is required.

L-45. Comment: ARB should provide more clarity as to the responsibility and authority of the market monitor. In addition, the role of the market monitor should be transparent to the market. We understand that ARB is planning to hire an independent market monitor. This is important because market monitoring is essential to help ensure reasonable market behavior and results, and to instill confidence with market participants and other stakeholders. CCEEB recommends that the Independent Market Monitor that ARB selects be established with authority to: (1) review bids prior to the running of any auction; (2) provide analysis of the competitiveness of any auction, preferably on an ex-ante basis (e.g. prior to running the auction); and (3) report findings and concerns to the ARB. (CCEEB3)

Response: No changes were made to the regulation based on the comments. These requested actions are part of program implementation and will be addressed as part of that process.

L-46. Comment: CARB states in the Section H of the Summary of Proposed

Modifications, “Modifications to section 95820”, that section 95820(a)(3) was modified to remove the requirement for the Executive Officer to place allowances into a holding account within 15 days of the effective date of the regulation as it is unlikely there will be a system with a holding account available within 15 days to meet this requirement. This highlights the fact that CARB is intent on promulgating a regulation that doesn’t have all the necessary support elements in place to effectively support what CARB is hoping to achieve. (VALERO2)

> **Response:** We made this change because the regulation comes into effect to allow registration of covered entities by January 1, 2012. However, the market and auction systems are not scheduled to begin operating until July 2012, to allow for the first scheduled auction. The enforcement of the first compliance year does not begin until January 1, 2013. The reason for the staggered startup of the main components of the program, as well as the elimination of the date referred to in the comment, was to ensure that the operating systems will be ready when each component of the program begins.

L-47. Comment: A strong Cap and Trade market design is vital to the success of the Cap and Trade program. SCE supports the Joint Utilities Group in recommending that ARB adopt a roadmap and market readiness checklist before beginning the program. (SCE3)

> **Response:** No changes were made to the regulation based on the comments, as these actions are related to program implementation.

L-48. Comment: We are concerned that language has not yet been added to the Regulation to incorporate the role of the market monitor and seek clarification from ARB regarding where the role and responsibilities of the monitor will be described. Specifically, we recommend that ARB designate in the Regulation a Market Monitor with the following authority and responsibilities:

1. Auction Certification. The Regulation requires that each quarterly auction be certified that it was conducted pursuant to the regulation prior to its official closing. PG&E recommends that the certification of the auction allow up to seven days for ARB and the Market Monitor to review the auction and associated calculations, review participant/group behavior or scan for other suspect activity, and certify results (similar to RGGI) prior to consummation of any trades from that auction. The result of certification would be a report that either:

   a. Certifies that the auction functioned properly, participant behavior appeared reasonable and verifies results (prices, including correcting any potential errors and winners), or

   b. Notes concerns with the auction (potential concerns could include, but are not limited to, buyer concentrations, suspect collusion or prices at unreasonable levels) and proposes resolution. Resolution could include declaring the auction a failure (and not executing trades), re-running the auction, or temporarily suspending the auction and compliance obligation.

2. Market Monitor Reports. A Market Monitor to monitor auction and bilateral markets and to issue reports after each quarterly auction and at least annually for bilateral markets.

3. Annual Report on Market Status. A consultant annually reviews the market, its price levels, participants progress toward compliance, whether any manipulation is occurring and report to participants and the ARB. Reports should be vetted with stakeholders and address their input questions. (PGE4)

> **Response:** No changes were made to the regulation based on the comments, as these actions are all part of program implementation.

L-49. Comment: PG&E encourages ARB to establish a system that allows participants to perform automated reconciliation with the compliance instrument registry. This will allow participants to obtain a complete allowance inventory of accounts in an electronic format to support their own internal automated reconciliation with the registry. (PGE4)

> **Response:** No changes were made to the regulation based on the comments, as such functionality would be part of program implementation. For security reasons, it is unlikely that any external system will be allowed to access the compliance instrument registry.

L-50. Comment: The ARB proposal has not adequately defined many of the tools (i.e., forms, registrations, procedures, software) required for a Cap and Trade program (even one with the proposed “soft start” in 2012). Hence, a smooth and efficient start of the program is uncertain. If development of appropriate tools is further deferred, efficient functioning of the program could be put in jeopardy. WSPA recommends that where ARB has identified specific dates for program implementation, but that will require ARB tools (such as registration forms) for successful implementation, those dates should be deleted and a timeframe instead be defined. For example, instead of saying the registration is required on January 1, 2012, the Regulation should say, registration is required 30 days after ARB publishes (releases) the registration tools. Further, WSPA recommends that ARB develop a schedule for development procedures and requirements associated with the Cap and Trade program to allow interested parties to develop their approaches in line with ARB concepts. This collaborative process will facilitate involvement by stakeholders and ensure broad input into details required by the Cap and Trade program. (WSPA3)

> **Response:** Many of the 'tools' listed in the comment are part of program implementation and do not have to be included in the regulation itself.
> As components of the infrastructure become operational, we are committed to having stakeholders provide feedback on the design and recommend improvements. We included specific deadlines in the regulation to ensure that the regulation is enforceable. The compliance start date was moved from 2012

to 2013 to ensure that all the regulatory elements are in place and fully functional. We have initiated activities to develop the necessary rule implementation infrastructure for the regulation, including a market tracking system to trade allowances and offsets; contracts for an auction services provider; a financial services provider; and a market monitor. We are also committed to providing continual public updates, with opportunity for stakeholder comment, on the implementation of the regulation.

Trading and Banking

L-51. Comment: WSPA disagrees that imposing holding limits is required to reduce market manipulation. The position limits included in the regulation are a rule developed by the CFTC to regulate futures markets. No agency has ever attempted to use such limitation to regulate the inventory or spot market as suggested in the regulations and nothing on the record supports such a position. To the contrary, evidence available from the administration of carbon markets in Europe suggests that auction frequency, not holding limits, can control the risk of market manipulation most effectively. As written, the proposed regulations limit the ability of WSPA companies to trade and cost optimize to a fraction of the amount needed. Modify section 95920(d)(3) as follows:

<u>(3) The holding account limit for compliance entities will be calculated pursuant to section 95920(c)(1) as two times the average of the entities previous two year's reported emissions</u>. (WSPA3)

Response: First, the response is not correct in its assertion that the holding limit was developed by the CFTC to regulate futures markets. The holding limit was developed in consultation with Jeffrey Harris, who was formerly employed at the CFTC.

Second, members of the EU ETS did not conclude that auction frequency alone can control the risk of market manipulation. They have other procedures, analogous to "responsibility levels" in U.S. commodity markets, which are part of EU national programs. In addition, the EU members have identified position and purchase limits as backstops in case anti-competitive conditions emerge. As to whether our approach is unprecedented, our selection of policy instruments is restricted by the Administrative Procedure Act, which limits our discretion in managing markets. We do not have the full range of policy instruments that are available to national agencies in the EU. For example, we cannot use responsibility levels because we cannot make ad hoc determinations of when limits must be reduced in response to judgments on market conditions. We cannot introduce position or purchase limits as backstop measures in response to short-term market conditions because we must adopt them through a lengthy rulemaking process.

The holding limit calculation would allow all covered entities to keep about 6 million MT of allowances, along with an unlimited amount of offsets, in their holding accounts during the first compliance period. This number rises to over 11 million MT in the second compliance period. These levels should give covered entities the opportunity to make profitable sales when they are able to identify short-term price increases. Many covered entities have informed us that they will procure as close in time as they emit, so we concluded that the limits will not overly restrict speculative behavior by covered entities.

L-52. Comment: Section 95922. We previously commented that unlimited banking could have the unintended consequence of the program not meeting the 2020 emissions goal. Provisions need to be added to limit the number of banked compliance instruments or the time that they can be banked. With the economic downturn it is likely that many facilities will be able to bank unused compliance instruments in the early years of the program and may not need to use them in the future. This may also lead to price fluctuations in the market. For example, in the last compliance period, if large amounts of banked compliance instruments are offered for sale, the price could drop dramatically which would limit the amount of on-site reductions made by facilities. This may make it even more difficult to achieve the transformative changes that will be needed to meet the 2050 greenhouse gas emission reductions target for the state. (SCAQMD4)

Response: No changes were made to the regulation based on the comments. The program was designed on forecasted emissions that included the impacts of the economic downturn.

M. OFFSETS

Limits on Offsets

Restrict Offsets to Local and/or In-State Offset Projects

M-1. (multiple comments)
Comment: Research shows that out-of-state offsets will increase criteria pollution. (David Roland-Holst, "Carbon Emission Offsets and Criteria Pollutants: A California Assessment," March, 2009, University of California, Berkeley.) Air pollution is worst in low-income communities and communities of color, such as the neighborhoods downwind from oil refineries in the LA area. We call upon ARB to eliminate out-of-state offsets and greatly reduce the allowed in-state offsets. It is embarrassing that over 85 percent of the GHG reductions could come from offsets. Relieve low-income communities and communities of color from this heavy burden. (EDLA)

Comment: Offsets should be limited to assure the integrity of the emission reductions and fulfill the letter and spirit of the law. Excessive reliance on offsets could open up loopholes that undermine the very purposes of California's AB 32 cap on emissions. Curbing global warming will require a fundamental transformation of our energy economy, a task that cannot be outsourced to other countries. Requiring California's largest polluters to reduce their own emissions will spur technological advances that can be exported to the rest of the world, bringing green jobs to the Golden State. If polluters are allowed to outsource their emission reductions to other sectors and jurisdictions, the clean-energy revolution will be delayed. Research shows that out-of-state offsets will increase criteria pollution. The staff proposal would allow polluters to offset almost half of the emission reductions required under this rule. That amount should be significantly reduced. (We supported the 10 percent limit in AB 1404, which was passed by the Legislature but vetoed by the Governor in 2009). (SIERRACLUBCA5)

Comment: We urge CARB to explore how it can give greater weight to offset credits from California agriculture compared to credits from other states and countries. Many of the agricultural activities that provide reduced GHG emissions have additional environmental and health benefits such as improved air and water quality. California should seek to maximize those additional environmental and health benefits by structuring the offset credit market to incentivize the use of credits from California first and outside of the state second. (CACAN3)

> **Response:** The commenters reference a University of California (UC) Berkeley study which they state demonstrates that allowing out-of-state offsets in the program would increase co-pollutant emissions in California. Contrary to the commenters' concerns, the facilities' ability to use offsets that originate outside of California will not cause an increase in co-pollution emissions in California. The UC Berkeley study found that if all facilities only purchased out-of-state offsets, then the potential co-pollutant benefits realized by a greenhouse gas cap-and-trade program would be less than if no offsets were allowed. This finding should

not be misinterpreted to imply that out-of-state offsets would lead to an increase in co-pollutant emissions in California.

Furthermore, as stated in the response to comments for the Staff Report, numerous studies have evaluated the potential for inequitable impacts from emissions trading programs on minority neighborhoods, racial and ethnic groups, and general community demographics, and found that trading did not have a disproportionate impact.

The most effective way to reduce the impacts of co-pollution emissions in low-income and disadvantaged communities is to implement programs that target reductions in co-pollutant emissions directly. While a GHG-focused program would likely reduce co-pollutant emissions along with GHG emissions, it is not the most effective mechanism for decreasing exposure to co-pollutants.

Although we anticipate that co-pollutant emissions would decrease under the cap-and-trade program, we are committed to monitoring the implementation of the regulation to identify and address any situations where the program results in an increase in criteria air pollutant or toxic emissions. In Resolution 11-32, the Board approved an adaptive management plan for the cap-and-trade program.

At least once each compliance period, we would use information collected through the mandatory reporting regulation, the cap-and-trade regulation, and other sources of information to evaluate how individual facilities are complying with the cap-and-trade regulation. The public will have ample opportunity to comment on these assessments. At least once a compliance period, we will update the Board on the adaptive management plan. Where necessary and appropriate, we will consult with the local air district, CDPH, and outside experts. We do not believe that tracking specific public health outcomes will provide data that will be useful to the adaptive management plan because many health impacts are not observed until years after exposure occurs and due to the low levels of exposure anticipated it would be difficult to observe a significant association, and extremely challenging to establish causation.

If adverse co-pollutant impacts are identified and can be attributed to the cap-and-trade regulation, we are committed to promptly developing and implementing appropriate responses through a public process, including consideration and approval by the Board as necessary.

The program imposes a limit on the amount of offsets that an individual covered entity can use for compliance. All offsets used for compliance are real reductions, albeit outside the cap. Allowing a limited number of offsets into the program provides cost-containment benefits and ensures that some GHG emissions reductions occur within the sectors covered by the cap-and-trade program. The program includes provisions that would allow a maximum of 201 $MMTCO_2e$ of offsets through the year 2020. This limit will be enforced through a limit on the use of offsets by an individual entity equal to eight percent of its compliance obligation. It is highly unlikely that the eight percent offset usage limit could result in 85 percent of the reductions required under the cap coming from offsets. Combined with the Allowance Price Containment Reserve, the eight percent limit ensures that a majority of reductions from the program come from sources covered by the program at expected allowance prices, while use of the reserve will relax that constraint if prices rise.

No Offsets/Reduce Number of Offsets

M-2. Comment: In regards to section 95854, we recommend that in the second and third compliance periods, the percentage of total emissions that would be permitted to come from offsets is reduced. We propose that no more than 2.5 percent of total emissions in the second compliance period and no more than one percent of total emissions in the third (and any subsequent) compliance period be permitted to come from any type of offset. This would be equivalent to roughly one-third of emission reductions from business as usual in the 2nd compliance period and 12 percent of emission reductions in the 3rd compliance period. These modifications in quantity will help promote technological innovation in the highest-emitting sectors, increase opportunities for in-state co-benefits (including air quality benefits), and reduce the risk that a high proportion of compliance credits will not represent real and additional reductions in emissions. We oppose any suggestion to have one offset usage limit through 2020. Limits on offsets should remain as a per compliance period percentage and not be counted cumulatively across compliance period. (UCS6, UCS7)

Response: We did not change the limit on the use of offsets in the program. We believe that a limited use of offsets is necessary in the program to contain costs and incentivize reductions in uncapped sectors. The program imposes a limit on what we believe is an appropriate amount of offsets that an individual covered entity can use for compliance. All offsets used for compliance are real reductions, albeit outside the cap. Allowing a limited number of offsets into the program provides cost containment benefits and ensures that some GHG emissions reductions occur within the sectors covered by the cap-and-trade program. The program includes provisions that would allow a maximum of 201 $MMTCO_2e$ of offsets through the year 2020. This limit will be enforced through a limit on the use of offsets by an individual entity equal to eight percent of its compliance obligation. Combined with the Allowance Price Containment Reserve, this limit ensures that a majority of reductions from the program come from sources covered by the program at expected allowance prices, while use of the reserve will relax that constraint if prices rise.

Unlimited Offsets/ Increase Number of Offsets

M-3. (multiple comments)
Comment: We believe that the level of assault from the environmental and environmental justice communities will never allow CARB to fully utilize offsets to the

degree that would ever give the regulated community any comfort. We lament the lack of approved protocols for offset development, and the convoluted fractions of fractions of compliance obligations allowed to be met through the use of offsets and their general politicization by those with radical environmental agendas. (CIPA)

Comment: CARB has established a very stringent framework both for existing offset protocols and for approving new offset protocols. These requirements are likely to limit the size of the offset market available to California businesses and offset developers. Given this level of stringency, CARB should not continue to set an arbitrary limit on the number of offsets that can be used to meet a compliance entity's surrender obligation. The proposed 8 percent limit is no more likely than the previous 4 percent limit to provide enough offsets to meet the needs of a growing economy in California. This arbitrary limit on the number of offsets that can be used increases costs and leakage. (AB32IG2)

Comment: The quantitative usage limit on offsets will only serve to increase the overall costs of compliance of the program. As long as offset credits are deemed by ARB to be real, permanent, and verifiable, there should be no restrictions on their use. Not only does it increase the costs of the program, but such usage limits may also inhibit investment in offset projects. This is particularly true in those projects with long-term planning horizons, where investors may be less willing to support development of large-scale or capital intensive offset projects if there is uncertainty as to whether they will be able to monetize the carbon reduction off-take portion of the project. This opposition to quantitative usage limits noted, Evolution Markets recognizes ARB has modified the provision to apply the limit to the triennial compliance period (or biannual compliance period for 2013-2014). This change, however, may not provide enough flexibility to compliance buyers to realize the full cost-saving potential of offsets or stimulate investment in capital intensive offset projects. Evolution Markets recommends ARB extend the period of time to which the quantitative usage limit would apply to the full length of the program—from 2013 to 2020. The added flexibility ensures each compliance entity has an opportunity to maximize use of low-cost offsets by allowing them to invest in offset projects or purchase offset credits in the market in an efficient and risk-managed manner. (EVMKTS2)

Comment: Offsets represent an important cost containment tool for many food processors and producers and should the economy ever rebound, offsets will be vital to keeping the cost of allowances from skyrocketing as industries begin to ramp up production to meet demand. CLFP recommends that CARB not take a restrictive approach to the use of emission offsets by Cap and Trade program participants such as limiting the number or percentage of offsets that can be used; the geographic location of offsets; or the types of offsets that would be eligible. (CALFP3)

Comment: Allowing the use and availability of a large quantity of offsets from the very beginning of the program will be crucial to the program's success. Policies that increase the likelihood of an inadequate supply of offsets and the inability to link to other Cap and Trade programs will greatly decrease the potential for a cost effective

California program. CLFP recommends that CARB instead focus on the quality of offsets; that they meet the requirements of being real, additional, quantifiable, verifiable, and permanent. As long as offsets meet that rigorous standard, then their use by regulated entities should not be limited for compliance purposes. (CALFP3)

Comment: CLFP recommends that the proposed 8 percent level be established as a floor, and that additional offsets be allowed as necessary to maintain costs of the program within acceptable limits. (CALFP3)

Comment: Section 95854 limits the volume of offsets that facilities can use for their annual and triennial compliance obligation to only 8 percent, thus artificially raising the cost of compliance. This restriction, combined with the expected use of auctions as a means to distribute the allowances will marginalize (render inconsequential) the use of offsets, reduce offset supply, discourage out-of-program sources that would otherwise be subject to CARB control (for it is only such sources that can create credits) from taking steps that would have otherwise be taken to reduce emissions, and increase the cost of compliance. Offset creators will be more likely to choose to expend their capital in regions that allow for the greater use of offsets and potential offset buyers will be more likely to choose to expand and possibly move their operations to regions that are not burdened with such restrictions. CantorCO2e recommends that CARB remove the quantitative restriction. Instead, limits should be based on quality of offset credits. Any offset credits which meet CARB's qualitative criteria should be allowed to be used by sources. (CANTORCO2E2)

Comment: Ag Council urges ARB to remove the 8 percent threshold of offsets allowed in a company's portfolio when surrendering allowances. Given the stringent criteria ARB is requiring to register an offset project, this arbitrary 8 percent threshold will only further stifle investment into offset projects. While it is an improvement over the 4 percent threshold which was previously suggested, 8 percent is only a minor step forward. (ACC4)

Comment: CARB should eliminate both quantitative and geographic limits on the use of qualified offsets to satisfy compliance obligations. Currently, CARB has proposed that a maximum of 8 percent of an industrial facility's compliance obligation can be met by offsets. This limit is unnecessary in light of CARB's stringent offset qualification rules, and it is also counterproductive as it could limit the cost effectiveness of CARB's GHG reduction program, particularly for California cement producers who have few, if any, additional cost-effective abatement opportunities available. In order to ensure adequate offset availability, CARB should not limit the geographical location of qualified offset projects. If CARB does maintain some limit on the use of offsets, limits should vary based on an industry's leakage category. The cement sector, with its high vulnerability to leakage, therefore should have a high limit (if any) on its ability to rely on offsets to meet its compliance obligations. (CSCME4)

Comment: Quantitative limits on the use of offsets may prevent cost effective greenhouse gas reductions. As long as ARB has rules in place to ensure that offset credits are high quality, there is no reason to implement artificial limits on their usage. ARB should be encouraging investment in projects and should understand the long time horizon required for planning and investing in projects. Limits on the use of offsets will serve to inhibit investment and create uncertainty regarding the monetization of the carbon reduction portion of the projects. If ARB believes that a limit is needed on the use of offsets, the Trust recommends that ARB extend the time period for the quantitative limit to the full length of the program (from 2013-2020). This allows a maximum number of years for a compliance entity to invest in projects, or purchase offset credits in the market, in an efficient and cost effective manner. (TCT)

Comment: CMTA opposes the limit on the use of qualified offsets. Stringent offset qualification rules and the need for CARB approval of any offset protocol will ensure only effective projects will be approved, and the rigorous process will likely constrain the availability of offsets in any event. There should be no additional, artificial constraints on the use of qualified offsets, and the evidence in the rulemaking record does not support a finding that limits in the use of offsets are necessary to meet the goals of AB 32. (CMTA3)

Comment: BP has previously commented on the importance of the role of offsets. Given the concerns about the potential economic impact of AB 32, the State of California's economy, the fact that significant emissions reductions in an already very efficient California energy production system will require long-term transformation, and the likelihood that California will be linking with few or no other Cap and Trade programs over the near term, we believe it is more important than ever that CARB seriously reconsider the enforcement of strict quantitative limits on offsets. Instead, CARB should look to incorporate the maximum use of design elements that control costs while maintaining the environmental integrity of the emission reduction goal. The use of offsets is a clear example of such a design element. The very restrictive quantitative limit on the use of offsets is compounded by what appears to be an incomplete, bureaucratic and potentially very exclusive offset-approval process. CARB staff should move expeditiously toward completion of an offset-approval process that ensures an adequate supply of offsets (especially early in the program), does not impose geographic limits (either explicit or implicit—through limited scope of approval), and that utilizes as much as possible existing offset protocols in use within California, the United States and globally. (BP2)

Comment: CERP recommends that ARB include a provision in the final regulations that would allow the quantitative offset limit to be modified in the future if allowance prices become too high. As CERP suggested in December 2010, the regulations should provide that if at any time half the allowances from the Allowance Price Containment Reserve have been purchased, additional cost containment should be provided by increasing the offset usage limit for that compliance period. If depletion of the Reserve occurs, ARB should also consider using revenue from the sale of Reserve allowances to purchase offsets which can then be used to replenish the Reserve. This system would allow for important price containment that would prevent the program from faltering under difficult economic conditions. (CERP4)

Response: We did not increase the amount of offsets allowed to be used in the program. The program imposes a limit on the amount of offsets that an individual covered entity can use for compliance. All offsets used for compliance are real reductions, albeit outside the cap. Allowing a limited number of offsets into the program provides cost-containment benefits and ensures that some GHG emissions reductions occur within the sectors covered by the cap-and-trade program. This limit will be enforced through a limit on the use of offsets by an individual entity equal to eight percent of its compliance obligation. Combined with the Allowance Price Containment Reserve, this limit ensures that a majority of reductions from the program come from sources covered by the program at expected allowance prices, while use of the reserve will relax that constraint if prices rise.

We recognize stakeholder concerns regarding offset supply. We may not adopt additional protocols as part of this cap-and-trade rulemaking. All offset protocols used in the compliance program must be adopted by the Board after undergoing a full regulatory process, including an ARB stakeholder process, in accordance with the Administrative Procedure Act, and an environmental review. We plan to look at further offset protocols for potential inclusion in the cap-and-trade program beginning in 2012. The details surrounding any new offset project types for which ARB adopts an offset protocol will be dealt in that rulemaking(s).

Carry Over of Offset Limit

M-4. (multiple comments)
Comment: ARB should fix the "buyer liability" issues with regard to offsets and allow carryover of the 8 percent compliance limit across years and compliance periods. Modify section 95854 as follows:

(a) Compliance instruments identified in section 95820(b) and sections 95821 (b),(c), and (d) are subject to a quantitative usage limit when used to meet a compliance obligation.

(b) The total number of compliance instruments identified in section 95854(a) that each covered entity may surrender to fulfill the entity's compliance obligation ~~for a compliance period~~ must conform to the following limit:

Oo/S must be less than or equal to Lo

In which:

Oo = Total number of compliance instruments identified in section 95854(a) submitted since January 1, 2013 to fulfill the entity's total compliance obligation ~~for the compliance period~~ through the current compliance year.

S = Covered entity's total compliance obligation beginning January 1, 2013 through the current compliance year.

Lo = Quantitative usage limit on compliance instruments identified in section 95854(a), set at 0.08. (CCEEB3)

Comment: The OWG both acknowledges and appreciates ARB’s improvement of Section 95854 by removing the applicability of the 8 percent quantification usage limitation to the annual compliance obligation. As the OWG considered this improvement, however, it came to light that the availability of offsets may not necessarily follow an artificial schedule based on calendar years. It's probable that the limited supply of offsets will become available in a lumpy manner, with greater amounts being available in the later compliance periods as forestry projects progressively sequester greater amounts of carbon and as additional protocols are added. This could lead to a scarcity of offsets in the earlier compliance periods and an unusable abundance in the later compliance periods. Also, the three-year limitation may place verification restrictions on Offset Project Operators (OPOs), forcing them to verify at times strictly by the calendar year. This may not be optimal or cost-effective for reducing emissions. A case in point is when variations in the reductions achieved by a forestry project may be out of sync with the strict 3-year compliance periods. Although a forestry offset project is only required in the Regulation to verify its carbon sequestration every 6 years, the project would need to, in fact, verify every 3 years in order to coordinate with the Covered entities' triennial compliance obligations. This would result in higher costs to the project developer with no additional benefit to sequestering additional emissions by the project. In order to overcome these artificially imposed problems and ensure that Covered entities have full access to an ample supply of offsets, ARB should modify the quantitative usage limitation to a running 8 percent of each Covered Entity's total compliance obligation. The OWG supports amendments to Section 95854 as follows

(b) The total number of compliance instruments identified in section 95854(a) that each covered entity may surrender to fulfill the entity's compliance obligation ~~for a compliance period~~ must conform to the following limit:

O_O/S must be less than or equal to L_O

In which:

O_O = Total number of compliance instruments identified in section 95854(a) submitted since January 1, 2013 to fulfill the entity's total compliance obligation ~~for the compliance period~~ through the current compliance year.

S = Covered entity's total compliance obligation beginning January 1, 2013 through the current compliance year. (OFFSETSWG3)

Comment: Section 95854(a) allows the use of the compliance instrument through to the end of the compliance period. WSPA believes this limited use of compliance instruments will only add to cost of compliance. WSPA recommends that the rule be amended to allow the use of the compliance instrument through to the end of the program, rather than to the end of a compliance period, as currently proposed. (WSPA3)

Comment: WSPA supports a robust offsets program as a critically important element of a cost-effective emission reduction and trading program. In the December rulemaking, Regulations creating the allowance reserve were adopted which take allowances from the cap in each compliance period and supplement that reduction in the cap by increasing the offset limits on specific facilities. Since the significant reductions in the cap due to the allowance reserve occurs throughout the program, ramping up in the second and third compliance period, WSPA proposes that the limit on offset use should extend to the full nine year period. (WSPA3)

Comment: As opposed to having an annual compliance obligation, ARB's quantitative usage limit on offsets (currently set at eight percent) will now apply to an entity's biannual compliance obligation for the first compliance period (2013-014) and triennial compliance obligation for the future compliance periods (2015-2017, 2018-2020). IETA is generally opposed to quantification limits. As long as only real, permanent, and verifiable offset credits are allowed into the market, arbitrary usage limits will only prevent further reductions of greenhouse gas emissions in a cost-effective manner. Furthermore, offset usage limits applied on the program and entity level inhibits investment in offset projects, particularly those with long-term planning horizons. Investors may be less willing to support development of large-scale or capital intensive offset projects if there is uncertainty as to whether it will be able to monetize the carbon reduction off-take portion of the project. These are the very projects that ARB hopes to foster with the offset program, as they are more likely to employ innovation in sustainable development and create good-paying green jobs. However, should quantification limits remain in place, IETA believes the modification from an application of the usage limit from an annual calculation to one based on the biannual or triennial compliance period is insufficient. In order to maximize flexibility, and therefore aid in reducing the costs of compliance, IETA recommends ARB extend the period of time to which the quantitative usage limit would apply to the full length of the program—eight years or from 2013 to 2020. The added flexibility ensures each compliance entity has an opportunity to maximize use of low-cost offsets by allowing them to invest in offset projects or purchase offset credits in the market in an efficient and risk-managed manner. In addition, this extension factors in the expectation that offsets are likely to be in short supply, especially at the program's start. (IETA3)

Comment: SCE continues to be concerned that ARB's offset policies are being implemented in a manner that will reduce the number of eligible offset projects brought to market. Furthermore, regulated entities may not be able to use offsets for the full 8 percent of emissions reductions authorized in the Regulation. Covered entities will not be able to substantially avoid direct emissions reductions using offsets. Currently, an overwhelming majority of the emissions reductions under AB 32 are already being achieved directly within California by regulated entities. Thus, the Cap and Trade program will comprise a relatively small share of the emissions reductions required to comply with AB 32, and the share of reductions due to offsets will be even smaller. Yet offsets, assuming sufficient supply, still have enormous potential to provide significant cost containment opportunities for the California emissions market. SCE offered detailed suggestions for implementation of ARB's offsets program in its December 2010 comments on the Proposed Draft Regulation. This process includes many steps such as the development and approval of protocols, verification services, third-party registries, offsets projects registration, and offsets certification and listing. SCE refers ARB staff to those earlier comments. The ARB offset program must be fully in place for the first compliance period in order to provide real cost containment, and SCE strongly urges ARB staff to take the necessary steps to ensure a robust supply of offsets by the first compliance period. SCE encourages the ARB to develop offset rules that will enable the State to achieve its AB 32 emission reduction goals efficiently and effectively. (SCE3)

Comment: SCE continues to have serious concerns about offset supplies in the first two compliance periods, which would limit compliance entities from using the offsets toward the full 8 percent of emissions reductions authorized in the Regulation. Offsets are a critical source of cost containment for regulated parties under AB 32. By contrast, concerns over concentrated offset use later in the Cap and Trade program are misguided, given that climate change is a global, long-term challenge, and the share of offsets retired in any particular compliance period is neither relevant nor environmentally important. As the regulated community anticipates the increase in offset supply in the later years of the program, ARB should allow covered entities the flexibility to use offsets up to 8 percent of reported emissions to date over the eight years of the program. In doing so, ARB would be assured that the use of offsets would never exceed 8 percent of the entity's compliance obligation to date, while affording flexibility to minimize the cost of compliance over the entire term of the Cap and Trade program. Modify section 95854 as follows:

> (a) Compliance instruments identified in section 95820(b) and sections 95821 (b), (c), and (d) are subject to a quantitative usage limit when used to meet a compliance obligation.
> (b) The total number of compliance instruments identified in section 95854(a) that each covered entity may surrender to fulfill the entity's compliance obligation ~~for a compliance period~~ must conform to the following limit:
>
> OO/S must be less than or equal to LO
>
> In which:
> OO = Total number of compliance instruments identified in section 95854(a) submitted <u>since January 1, 2013</u> to fulfill the entity's <u>total</u> compliance obligation ~~for the compliance period~~ <u>through the current compliance year</u>.
> S = Covered entity's total compliance obligation <u>beginning January 1, 2013 through the current compliance year</u>.
> LO = Quantitative usage limit on compliance instruments identified in section 95854(a), set at 0.08. (SCE3)

Comment: The Joint Utilities propose that the quantitative limits for the use of offsets in section 95854 be revised to account for all offsets submitted by an entity since the start of the Cap and Trade program and the total compliance obligation of the entity since the start of the Cap and Trade program, rather than looking at the compliance obligation for a single compliance period. Modify section 95854(b) as follows:

> (b) The total number of compliance instruments identified in section 95854(a) that each covered entity may surrender to fulfill the entity's compliance obligation ~~for~~

~~a compliance period~~ must conform to the following limit:

O_O/S must be less than or equal to L_O

In which:
O_O = Total number of compliance instruments identified in section 95854(a) submitted since January 1, 2013 to fulfill the entity's total compliance obligation ~~for the compliance period~~ through the current compliance year.

S = Covered entity's total compliance obligation beginning January 1, 2013 through the current compliance year.

L_O = Quantitative usage limit on compliance instruments identified in section 95854(a), set at 0.08. (JOINTUTILITIES)

Comment: For the most efficient use of the offset limit, all offsets submitted by the entity since the start of the Cap and Trade program should be included in the calculation of the offset limit, not just the offsets submitted in a particular compliance period. The total compliance obligation of the entity since the start of the cap and trade program should also be included in this formula, not just the compliance obligation in a particular compliance period. Modify section 95854 as follows:

(a) Compliance instruments identified in section 95820(b) and sections 95821 (b), (c), and (d) are subject to a quantitative usage limit when used to meet a compliance obligation.

(b) The total number of compliance instruments identified in section 95854(a) that each covered entity may surrender to fulfill the entity's compliance obligation ~~for a compliance period~~ must conform to the following limit:

O_O/S must be less than or equal to L_O

In which:

O_O = Total number of compliance instruments identified in section 95854(a) submitted since January 1, 2013, to fulfill the entity's total compliance obligation ~~for the compliance period~~ through the current compliance year.

S = Covered entity's total compliance obligation beginning January 1, 2013, through the current compliance year.

L_O = Quantitative usage limit on compliance instruments identified in section 95854(a), set at 0.08.

(c) The number of sector-based offset credits that each covered entity may surrender to meet the entity's compliance obligation for a compliance period must not be greater than 0.25 of the LO for the first compliance period and not more than 0.50 of the LO for subsequent compliance periods. (SCPPA6)

Comment: Section 95854 Quantitative Usage Limit on Designated Compliance Instruments—Including Offset Credits.

(a) Compliance instruments identified in section 95820(b) and sections 95821 (b), (c), and (d) are subject to a quantitative usage limit when used to meet a compliance obligation.
(b) The total number of compliance instruments identified in section 95854(a) that each covered entity may surrender to fulfill the entity's compliance obligation ~~for a compliance period~~ must conform to the following limit:

O_o/S must be less than or equal to LO

In which:

O_o = Total number of compliance instruments identified in section 95854(a) submitted <u>since January 1, 2013</u> to fulfill the entity's <u>total</u> compliance obligation for the compliance period <u>through the current compliance</u> period.
S = Covered entity's <u>total</u> compliance obligation <u>beginning January 1, 2013 through the current compliance year</u>.
LO = Quantitative usage limit on compliance instruments identified in section 95854(a), set at 0.08.
(c) The number of sector-based offset credits that each covered entity may surrender to meet the entity's compliance obligation for a compliance period must not be greater than 0.25 of the LO for the first compliance period and not more than 0.50 of the LO for subsequent compliance periods.

ARB proposes a quantitative usage limit of 8 percent for offsets (i.e. a covered entity can meet up to 8 percent of its compliance period obligation with offsets). LADWP recommends that the offset limit be calculated on a cumulative basis as opposed to a compliance period basis. This would ensure that a covered entity's use of offsets for compliance in any given period does not exceed 8 percent of covered emissions. (LADWP4)

Comment: In the first compliance period, the supply of offsets is likely to be inadequate to cover 8 percent of emissions, as would be permitted under the proposed Regulation. To address this situation, PG&E encourages expedited approvals of additional protocols and proposes a simple method to allow complying entities the flexibility to use offsets up to the 8 percent limit over the entire Cap and Trade program. (PGE4)

Comment: Evolution Markets is concerned that the offsets program, as proposed to be amended by ARB, could seriously limit its effectiveness in containing costs to California consumers. Rules proposed to encourage early investment in carbon offsets are administratively complex and burdensome. There could likely be a bottleneck of supply or too high a cost of issuance, which could limit the availability of early action offsets and lead to higher compliance costs. In addition, the ability for ARB to invalidate offset credits once issued and used for compliance—and putting the liability of replacement on the buyer—will likely adversely impact investment in offset projects. Compliance entities or other firms may be less willing to finance an offset project considering the unprecedented liability. This will be particularly true for small offset project developers who cannot provide a compliance guarantee for the credits they sell. This will result in fewer offset projects developed, less offset credit supply, and higher costs of compliance. (EVMKTS2)

Comment: In an effort to provide flexibility and reduce compliance costs to regulated entities, CalChamber believes entities should be allowed the flexibility of banking unused offsets on a year-to-year basis. Another mechanism that should be available to regulated entities is the ability to trade the balance of their remaining unused offsets to another company. (CALCHAMBER)

Comment: In an effort to provide flexibility and reduce compliance costs to regulated entities, these entities should be allowed the flexibility of banking unused offsets on a year-to-year basis. Another mechanism that should be available to regulated entities is the ability to trade the balance of their remaining offsets to another company. (CMTA3)

Comment: In an effort to provide flexibility and reduce compliance costs to regulated entities, companies should be allowed the flexibility of banking unused offsets on a year-to-year basis. Another mechanism that should be available to regulated entities is the ability to trade the balance of their remaining offsets to another company. (CALFP3)

Comment: In order to promote lower cost compliance and market efficiency, CARB should allow facilities to carry forward and trade unused offset capacity. Facilities and market participants have expressed concern that they cannot bank unutilized offset compliance requirements for use between compliance periods. As a means to reduce compliance costs and provide flexibility, sources should be given the ability to carry forward and trade unused offset capacity. (CANTORCO2E2)

Comment: CERP continues to believe that the eight percent quantitative limit on offsets will significantly raise the cost of compliance and is unnecessarily restrictive. Because it appears likely that there will not be sufficient offset supply in the early compliance periods to meet demand, covered entities will not be able to purchase the maximum number of offsets and could lose the cost containment benefits that offsets provide. As an alternative, CERP supports the proposal to modify the regulations to apply the eight percent limit to provide that covered entities are able to use unused offsets in future compliance periods as long as their total offset usage never exceeds eight percent of their compliance obligation. This would entail changing the regulations to allow the eight percent usage limit to apply over the entire term of the program to date. This could provide important cost relief if offset supply is low in early years of the program and compliance entities are therefore only able to employ a small number of offsets during those periods. (CERP4)

Comment: In order for offsets to provide cost control, they must be available to the market. In addition to the previously mentioned concerns about quantitative limits and a bureaucratic approval process, there is also the potential that even if offsets are available, some regulated entities may not be inclined or able (for whatever reason) to make use of offsets—a development that can affect all market participants. CARB should monitor the quantity of offsets used as compared to the allowed limit, and create a system to carry over to new compliance periods and distribute amongst all market participants, the ability to use offsets unused in a previous compliance period. For example, if offsets make up only 6 percent of compliance instruments in the first compliance period (due to a lack of offset supply, use, or for other reasons), the unused 2 percent should allow for all regulated parties to use 10 percent (i.e. 8 percent plus 2 percent) offsets in the next compliance period. (BP2)

> **Response:** The regulation allows offsets to account for eight percent of an individual entity's emissions over a compliance period. We did not allow the carryover of unused offsets between compliance periods, to ensure that emission reductions are being achieved by capped sources throughout the life of the program. Keeping it to the compliance period allows some flexibility by giving three years to total emissions, but still requires emission reductions to come from within capped sectors in all years of the program.

M-5. (multiple comments)
Comment: We oppose any suggestion to have one offset usage limit through 2020. Limits on offsets should remain as a per compliance period percentage and not be counted cumulatively across compliance periods. (UCS6)

Comment: Camco supports the revision made from the previous version of the Regulations (i.e. not requiring utilization of the full 8 percent limit on offsets within one year) to permit covered entities to carry-over their offset allowance within compliance periods. We believe this strikes the right balance between providing flexibility to covered entities while at the same time stimulating the development of the offset market. However, we would not support the carry-over from one compliance period to the next as we are concerned this may constrain the development of the offset sector and make demand for offsets, and thus the development of projects, irregular and unpredictable particularly in the early stages of the market. Offsets will provide an important cost containment mechanism for the market, particularly in the later stages of the program beyond 2015. Demand for offsets through the initial compliance period will provide all market participants with the opportunity to become familiar with this aspect of the program and should allow project developers, verifiers, registries and other service providers time to develop to meet gradually increasing demand. (CIG2)

> **Response:** We did not make changes to the regulation to allow one offset usage limit through 2020.

Calculation of the Quantitative Limit on Offsets

M-6. (multiple comments)
Comment: Section 95854 was revised to clarify that the quantitative usage limit on offsets is 8 percent per compliance period, rather than on an annual basis. SCE thanks ARB staff for making this clarification to address stakeholder concerns about offset supply. (SCE3)

Comment: In section 95854(b) of the 15-day changes document, CARB clarifies what was likely an identical requirement in the prior version of the Regulation that eight percent of an "entity's compliance obligation for the compliance period" can be satisfied by compliance instruments subject to a quantitative usage limit (for example offsets). Although this does not appear to be a substantive change to the rule from the prior version, it does clarify the quantitative usage limit. (EDF4)

> **Response:** Thank you for your support on the modifications to the regulation.

Ensuring Offset Quality and Criteria of AB 32

M-7. Comment: The use of offsets as a compliance instrument presents substantial risks of not achieving the emissions reductions called for in AB 32. When offsets credits are generated by business-as-usual projects that were going forward, regardless of the offsets payments, the companies under the cap are able to emit more than the cap, but equivalent additional emissions aren't reduced elsewhere. Companies are simply paying project owners outside of the cap to do what they were doing anyway. The Cap and Trade program is effectively weakened by the number of non-additional business-as-usual offset credits allowed for compliance. By allowing most of the Cap and Trade emission reductions to come from offsets, the state substantially reduces opportunities to realize in-state co-benefits from AB 32. (UCS6)

> **Response:** We disagree that the inclusion of offsets does not require capped sources to reduce emissions. The program imposes a limit on the amount of offsets that an individual covered entity can use for compliance. All offsets used for compliance are real reductions, albeit outside the cap. Allowing a limited number of offsets into the program provides cost-containment benefits and ensures that some GHG emissions reductions occur within the sectors covered by the cap-and-trade program. The program includes provisions that would allow a maximum of 201 $MMTCO_2e$ of offsets through the year 2020. This limit will be enforced through a limit on the use of offsets by an individual entity equal to eight percent of its compliance obligation, or total emissions. Combined with the Allowance Price Containment Reserve, this limit ensures that from the program come from sources covered by the program at expected allowance prices, while use of the reserve will relax that constraint if prices rise.
>
> In regard to additionality, we believe that the Compliance Offset Protocols, in conjunction with all of the strict and thorough requirements in the regulation

regarding offsets, meet the requirements of AB 32. The Compliance Offset Protocols adopted under the cap-and-trade regulation have been established with multiple levels of review, use conservative methods to account for uncertainty and emissions leakage, and establish the additionality of offset projects in setting project baselines.

M-8. Comment: The proposed offsets represent a substantial portion of required reductions. The Regulation allows up to 8 percent of all compliance obligations to be met with offsets. CARB notes that a reduction is required from projected 2020 emission levels of 507 million metric ton CO_2E to 427 million metric ton CO_2E emissions, current 2011 levels are not noted, nor is the percentage reduction needed to reach the goal of 1990 levels by 2020. However, the Electric Power Research Institute's paper "Overview of the California Greenhouse Gas Offsets Program," dated April 2011, states at page 10 that if the maximum quantity of offsets is submitted for compliance, offsets could be used to satisfy as much as 85 percent of required reductions (see http://globalclimate.epri.com/doc/EPRI_Offsets_W10_Background%20Paper_CA%20Offsets_040711_Final2.pdf). Even if a smaller percentage of compliance obligations are met with offsets, it is clear that offsets are intended to be a substantial portion of required reductions and their failure to represent real, additional, enforceable reductions could be extremely damaging to California's efforts to address climate change, as well as to efforts of the many states and countries expected to follow California's lead. See also, Offsets Could Make Up 85 percent of Calif.'s Cap-and-Trade Program, New York Times, August 8, 2011 at http://www.nytimes.com/gwire/2011/08/08/08greenwire-offsets-could-make-up-85-of-califs-cap-and-tra-29081.html?emc=eta1, in which CARB staff confirms that it is possible that offsets could make up 85 percent of reductions under the proposed program. (WILLIAMSZ2)

Response: We did not change the limit on the use of offsets in the program. The program imposes a limit on what we believe is an appropriate amount of offsets that an individual covered entity can use for compliance. All offsets used for compliance are real reductions, albeit outside the cap. Allowing a limited number of offsets into the program provides cost-containment benefits and ensures that some GHG emissions reductions occur within the sectors covered by the cap-and-trade program. The program includes provisions that would allow a maximum of 201 $MMTCO_2e$ of offsets through the year 2020. It is highly unlikely that the eight percent offset usage limit could result in 85 percent of the reductions required under the cap coming from offsets. Combined with the Allowance Price Containment Reserve, the eight percent limit ensures that a majority of reductions from the program come from sources covered by the program at expected allowance prices, while use of the reserve will relax that constraint if prices rise.

M-9. (multiple comments)
Comment: We believe that offset projects registered under an approved protocol should not cause significant adverse effects on human health or the environment, regardless of the location of the project. (UCS6, UCS7)

Comment: Modify section 95973 as follows:

(a) General Requirements for Offset Projects. To qualify under the provisions set forth in this article, an Offset Project Operator or Authorized Project Designee must ensure that an offset project must:

> add: <u>(e) not cause significant adverse effects on human health or the environment;</u> (UCS7)
>
> **Response:** No change was made to the regulation. We agree that any Compliance Offset Protocols approved in the cap-and-trade regulation must undergo a CEQA review. These protocols are designed to avoid significant adverse effects on human health or the environment. This environmental review is part of the rulemaking process.

M-10. Comment: Please do not use forest carbon projects to offset emissions from California industries. Please cut emissions at the source. (GIESE)

> **Response:** We do not agree that forest projects should not be allowed into the program. The program imposes a limit on what we believe is an appropriate amount of offsets that an individual covered entity can use for compliance. All offsets used for compliance are real reductions, albeit outside the cap. Allowing a limited number of offsets into the program provides cost-containment benefits and ensures that some GHG emissions reductions occur within the sectors covered by the cap-and-trade program. The program includes provisions that would allow a maximum of 201 $MMTCO_2e$ of offsets through the year 2020. This limit will be enforced through a limit on the use of offsets by an individual entity equal to eight percent of its compliance obligation, or total emissions.
>
> In addition, we believe that the Compliance Offset Protocols, in conjunction with all of the strict and thorough requirements in the regulation regarding offsets, meet the requirements of AB 32. The Compliance Offset Protocols adopted under the cap-and-trade regulation have been established with multiple levels of review, use conservative methods to account for uncertainty and emissions leakage, and establish the additionality of offset projects in setting project baselines.

M-11. Comment: The Board should close potential loopholes in the offset process by giving the Executive Officer explicit authority to deny any offset proposals that do not meet standards, and should ensure that the same offset project cannot be sold more than once through different registries. (SIERRACLUBCA5)

Response: We agree with the suggested change and modified the proposal to give the Executive Officer the exclusive authority over offset proposals, and added language in the verification section to delete Offset Project Registries from the appeals process for Adverse Verification statements. This clarification was made to be consistent with the MRR, and reflects stakeholder comments that the appeals process should only be limited to determinations made by the Executive Officer of ARB and that ARB should be the only one to make these determinations. We also clarified that ARB makes the final determination on whether or not ARB offsets credits should be issued and whether they meet all requirements of the regulation.

In addition we added new section 95975(c)(5) to the regulation. This section requires Offset Project Operators or Authorized Project Designees to disclose any offset credits issued for the same project for any other purposes in any other program. In addition, we added new attestations to section 95981(c). Offset Project Operators and Authorized Project Designees must make these attestation(s) in order for ARB to issue offset credits. Also, if we find that ARB offset credits were issued to the offset project for the same GHG reductions or GHG removal enhancements, we may invalidate the ARB offset credits pursuant to section 95985. This provision addresses double-counting of the GHG reductions or GHG removal enhancements in multiple programs.

M-12. Comment: ARB Must Include Grievance Mechanisms and Appeals Processes for Offset Credits. Section 95972, ARB should require that all offset protocols establish environmental and social safeguard standards, and also provide a grievance or compliant mechanism to allow affected citizens and communities to hold offset developers accountable for adhering to the policies and procedures within the protocol. We recommend that ARB provide impartial, independent, transparent and credible accountability mechanisms for human rights violations and non-compliance of any and all other regulatory provisions of either California or the jurisdiction where the offset credit is issues. The mechanism should have the authority to serve in both dispute-resolution and compliance functions. The processes for submitting a complaint should allow for affected individuals and communities of varying capabilities to effectively communicate their concerns and make a complaint without the need to hire outside experts.

Section 95980 and 95981: Because of the substantial evidence indicating that a significant proportion of offset projects, particularly those in the Clean Development Mechanism (CDM), do not meet even basic regulatory requirements or actually mitigate global climate change, ARB should provide an appeals process for ARB and registry offset credits. Such an appeals process should be established to ensure accountability for environmental integrity of offsets, and be fair, objective and effective. The appeals process should be broadly available to civil society and affected communities. Appeals must be available for decisions to credit a project on the basis of both procedural and substantive violations. Stakeholders must be afforded the right to request a review of registration or issuance requests in order to avoid unnecessary appeals. The time within which appeals may be brought should not be limited where new, material facts come to light indicating that an offset project does not meet the core requirements. Finally, an accurate and complete record upon which the appeal is based must be compiled and made publicly available. (FRIENDSOFEARTH2)

Response: We designed our regulatory offset verification program to provide a transparent process by which we and the public can review offset project documentation and verification documents and fully understand any findings uncovered during the course of verification of an offset project by an ARB-accredited verification body. We will also develop an audit and oversight program for offset project verifications. All oversight functions are part of implementation and need not be specified in the regulation. We understand some of the problems exhibited under the CDM program and have designed our program to ensure those same types of issues do not happen here. We may also invalidate an offset if it is later found to not meet the requirements of the regulation, or environmental, and health and safety laws. If at any point a stakeholder is concerned about a particular project, the stakeholder may notify us.

Our analysis indicates that the cap-and-trade regulation is expected to have a beneficial impact on air emissions by reducing emissions of criteria pollutants and toxics. Based on the available data, current law and policies that control industrial sources of air pollution, and expected compliance responses, we believe that emission increases due to the regulation at the statewide, regional, or local level are extremely unlikely, at best. Nevertheless, we are committed to monitoring the implementation of the cap-and-trade regulation to identify any situations where the cap-and-trade program has led to an increase in criteria pollutant or toxic emissions. In Resolution 11-32, the Board approved an adaptive management plan. This plan commits ARB to review information from local air districts regarding permit modifications and new permit applications for covered sources. This information will be used to identify compliance activities that could lead to increased emissions, and to determine whether further investigation of potential criteria pollutant and toxic emissions is warranted. If unanticipated adverse localized emissions impacts that can be attributed to the cap-and-trade regulation are identified during this periodic review, we will consider whether these impacts affect the achievement of the program objectives. If so, we will promptly develop and implement appropriate responses.

M-13. Comment: General Requirements for Compliance Offset Protocols and Credit are Insufficient; General requirements are of little use if not complemented by robust verification processes to ensure that requirements are actually being met. Section 95972 identifies general requirements for compliance offset protocols. While these requirements, in principle, would assist in ensuring environmental integrity of compliance offset credit generated through approved protocols, we see no assurances that these principles are being met in either domestic offset protocols (see Section 7) or in ongoing policy discussions to develop international sector-based REDD credits (see Section 10). The Board Resolution requires the Executive Officer (EO) to review compliance offset protocols and approve any necessary changes to ensure consistency throughout the program. The EO must ensure that these concerns are addressed prior to implementation of the program. Some of these requirements are further undermined by weak, insufficient measurement and verification requirements (see Section 6 below). General requirements are of little use if not complemented by robust verification processes to ensure that requirements are actually being met (FRIENDSOFEARTH2).

Response: We believe that the Compliance Offset Protocols in conjunction with all of the strict and thorough requirements in the regulation regarding offsets meet the requirements of AB 32. The Compliance Offset Protocols adopted under the cap-and-trade regulation have been established with multiple levels of review, use conservative methods to account for uncertainty and emissions leakage, and establish the additionality of offset projects in setting project baselines. The regulation requires that all Compliance Offset Protocols address activity-shifting and market-shifting leakage. Each protocol incorporated by reference, including the forest protocol, accounts for leakage in the quantification of the reductions or removals achieved by the offset projects. In addition, when uncertainty exists in quantifying GHG reductions, we will only issue offset credits when there is a high level of confidence that reductions actually occurred. The regulation employs a principle of conservativeness in the quantification of emissions reductions. This method will ensure that the accounting will underestimate, rather than overestimate, any reductions when there is a high level of uncertainty.

We agree that offset protocols must ensure environmental integrity. Generally, we do not include implementation-related procedures in our regulations. We plan to develop guidance documents related to the protocol approval process in 2012. In addition, all offset protocols used in the compliance program must be adopted by the Board after undergoing a full regulatory process, including an ARB stakeholder process, in accordance with the Administrative Procedure Act, and an environmental review. We plan to look at further offset protocols for potential inclusion in the cap-and-trade program beginning in 2012. The details surrounding any new offset project types for which ARB adopts an offset protocol will be dealt with in that rulemaking.

We disagree that the program includes a weak and insufficient verification program. The regulation proposes a robust monitoring program for offset projects—the verification that the offsets are real, additional, and enforceable, and that Offset Project Operators, verifiers, and Offset Project Registries are operating according to regulatory requirements. In addition to the ARB audits, Offset Project Registries are required to conduct oversight of their registry program and randomly audit verifications to ensure that our regulatory requirements are being met by Offset Project Operators and verification bodies. We will provide rigorous oversight of our approved Offset Project Registries.

In addition, we designed our regulatory offset verification program to provide a transparent process by which we can review verification documents and fully understand any findings uncovered during the course of verification of an offset project by an ARB-accredited verification body. We will also develop an audit and oversight program for offset project verifications. All oversight functions are part of implementation and need not be specified in the regulation.

This comment falls outside the scope of the first 15-day changes to the regulation. Because the comment falls outside the scope of the rulemaking, no further response is required. Furthermore, there are no provisions that allow ARB to accept REDD credits at this time.

M-14. (multiple comments)
Comment: Section 95975(c)(5) requires an Offset Project Operator to disclose issued credits by any mandatory or voluntary program for the same offset project. Why shouldn't the Offset Project Operator be prohibited from claiming any offsets for such "already used" reductions, rather than simply being required to disclose them? (SCAQMD4)

Comment: We strongly recommend that CARB also formally reach out to other voluntary and mandatory carbon crediting regimes to track registered reductions and investigate possible instances of double counting. (UCS6)

Comment: CARB should formally reach out to registries and other compliance regimes to aide in ensuring that each offset credit used for compliance has not been claimed by another person or entity under any GHG compliance program. (UCS7)

Comment: Current Draft Regulation Allows for Double Counting of Emissions. Section 95975 (c)(5) merely requires the Offset Project Operator and any Authorized Project Designees to disclose credits issued for the same offset project being listed. ARB must ensure that there is no double counting of emissions reductions credits in the ARB program alongside other voluntary or compliance markets, as this totally defeats the objective of the program to deliver emissions reductions. (FRIENDSOFEARTH2)

Response: In addition to requirements in section 95975(c)(5), we added new attestations to section 95981(c). Offset Project Operators and Authorized Project Designees must make these attestation(s) in order for us to issue offset credits. Also, if we find that ARB offset credits were issued to the offset project for the same GHG reductions or GHG removal enhancements, we may invalidate the ARB offset credits pursuant to section 95985. This provision addresses-double counting of the GHG reductions or GHG removal enhancements in multiple programs.

M-15. Comment: Section 95970 of the Cap-and-Trade regulation restates the mandate of AB 32 that a compliance offset credit must “represent a GHG emission reduction or GHG removal enhancement that is real, additional, quantifiable, permanent, verifiable, and enforceable." However, section 95971, "Procedures for Approval of Compliance Offset Protocols," identifies no actual procedures to ensure that adopted protocols satisfy these requirements, instead expressing a general commitment to provide public notice and opportunity for public comment. Section 95972, "Requirements for Compliance Offset Protocols," provides a list of general requirements for offset protocols, but no specific criteria or standards by which to determine the achievement of those requirements. The result of these sections is that there is no clear, consistent process identified for the adoption of compliance offset protocols.

The establishment of specific, standardized, quantitative criteria to be applied in the review of compliance offset protocols is critical to providing clarity, transparency, and consistency in offset protocols and the offset credits they generate. The Cap-and-Trade regulation should identify explicit determinations, based on standardized criteria, which ARB will apply in their evaluation of all offset protocols. For example, the regulation should require specific determination of the risk of non-additionality, reversal, and fraud associated with an offset protocol, provided in the context of the volume of offset credits an offset protocol is expected to generate, and a comparison of these factors among project types within an offset protocol and among offset protocols. Requirements for offset credit buffer pool contributions must be based on these assessments of risk and the volume of offset credits an offset protocol is expected to generate.

Without specific determinations based on consistent, standardized criteria, the Cap-and-Trade regulation does not provide that the review of offset protocols will ensure that offset credits are real, additional, quantifiable, permanent, verifiable, and enforceable. We understand that the wide variation in potential offset projects make the development of specific criteria challenging. However, it is precisely this tremendous variation in the character of offset projects that makes the use of standardized, quantitative criteria necessary to guard against ad hoc reviews that are inconsistent and potentially influenced by the demand for greater volumes of offset credits.

To use the example of the Compliance Offset Protocol U.S. Forest Projects ("Forest Offset Protocol"), this protocol contains a number of inadequacies that substantially increase the risk that the Forest Offset Protocol will generate non-additional offset credits. For example, under the Forest Offset Protocol, forest offset projects are not prohibited from shifting timber harvesting from project areas to elsewhere in their land ownership, and are not even required to report such "leakage;" forest offsets provide a much lower degree of permanence than the other adopted offset projects; forest offsets carry a much greater risk of reversal than offsets from the other adopted protocols; and the forest offset protocol relies significantly on carbon sequestration in a pool beyond the knowledge and control of the project operator, and which is therefore much more uncertain and unenforceable than other offset protocols. The current projections that California's Cap-and-Trade program will rely on offsets from the Forest Offset Protocol more than from any other offset protocol should be included in the context for evaluating the protocol and addressing inadequacies. Offset protocols should only be adopted, and should remain valid for new projects, only if the project types credited under the protocol are not likely to be pursued, or would be pursued at significantly lower rates, in the absence of the offset protocol, and if the business-as-usual reductions that are inadvertently credited under the protocol are counter-balanced by conservative methods to calculate emissions reductions. At a minimum, for the project types allowed to generate credits under offset protocols, ARB should thoroughly assess: the factors that influence project development decisions; the expected influence of AB 32 offsets credits on those decisions; the business-as-usual activities that are likely to go forward regardless of the ability to generate offsets credits; and whether the business-as-usual reductions that are inadvertently credited under the protocol are counter-balanced by conservative methods to calculate emissions reductions.

Finally, the regulation should require that all protocols use a baseline that reflects the most stringent combination of statutory and regulatory requirements between California and the jurisdiction where the offset project is located. This would avoid creating a perverse incentive for states to refrain from enacting regulation as strict as in California, since the enactment of such regulation could lead to the generation of fewer carbon credits from activities in their state. States with weaker regulations will have weaker baselines that could lead to the generation of larger numbers of offset credits from the same activity. The Center for Biological Diversity has submitted a separate comment letter in conjunction with other organizations on this topic, and those comments are incorporated here by reference. (CBD4)

> **Response:** Thank you for your comment. We agree that offset protocols must ensure that GHG reductions and that GHG-removal enhancements resulting from the use of them meet AB 32 requirements. Generally, we do not include implementation-related procedures in our regulations. We plan to develop guidance documents related to the protocol approval process in 2012. In addition, all offset protocols used in the compliance program must be adopted by the Board after undergoing a full regulatory process, including an ARB stakeholder process, in accordance with the Administrative Procedure Act, and an environmental review. We plan to look at further offset protocols for potential inclusion in the cap-and-trade program beginning in 2012. The details surrounding any new offset project types for which ARB adopts an offset protocol will be dealt with in that rulemaking.
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> In order to ensure that GHG reductions and GHG removal enhancements credited as offsets are real, the regulation requires that all Compliance Offset Protocols address activity-shifting and market-shifting leakage. Each protocol incorporated by reference, including the forest protocol, accounts for leakage in the quantification of the reductions or removals achieved by the offset projects. In addition, when uncertainty exists in quantifying GHG reductions, we will only issue offset credits when there is a high level of confidence that reductions actually occurred. The regulation employs a principle of conservativeness in the quantification of emissions reductions. This method will ensure that the accounting will underestimate rather than overestimate any reductions when there is a high level of uncertainty.

In regard to regulatory additionality, we intend to implement this policy through the adoption of each Compliance Offset Protocol and do not find it necessary to include language regarding this in the regulation itself. The decision to only include offset projects that qualify based on a regional additionality test throughout the WCI was made by the Partners to ensure that offset projects will be developed in WCI Partner jurisdictions and to ensure that a portion of the revenues generated from offsets would be generated in-state. WCI Partners do not want to create a program that pays parties in other states and provinces to undertake activities that they are requiring their sources to undertake by capping them or applying other direct regulations to such activities. The four Compliance Offset Protocols contain criteria and tests to ensure that the projects and resulting offset credits are additional.

M-16. (multiple comments)
Comment: We recommend the following protocol requirements be added to the Regulation. These requirements are essential to fulfill the meaning of "real" and "additional" and are more specific than the criteria in the draft regulation. Protocols should only be adopted, and should only remain valid for new projects, if:

- there is a very high level of confidence that the number of credits that will be generated under the protocol will not exceed the reductions enabled by that protocol;
- the project types credited under the protocol are not likely to be pursued, or would be pursued at significantly lower rates, absent being eligible as part of a compliance offset protocol; and
- the business-as-usual reductions that are inadvertently credited under the protocol are counter-balanced by conservative methods to calculate emissions reductions. (UCS6, UCS7)

Comment: The Regulation should incorporate specific procedures for adopting new protocols and periodically reviewing existing protocols consistent with the above criteria (see prior UCS7 comment). At a minimum, for the project types allowed to generate credits under offset protocols, CARB should thoroughly assess:

- the factors that influence project development decisions;
- the expected influence of AB 32 offsets credits on those decisions;
- the business-as-usual activities that are likely to go forward regardless of the ability to generate offsets credits; and
- whether the business-as-usual reductions that are inadvertently credited under the protocol are counter-balanced by conservative methods to calculate emissions reductions.
- Moreover, periodic reviews of existing protocols should assess the influence that the protocol has already had on new project development.

In addition, each approved protocol should conservatively account for uncertainty in quantification factors for the offset project type. Each approved protocol should use a baseline that reflects the most stringent combination of statutory and regulatory requirements between California and the jurisdiction where the offset project is located. CARB should monitor research advances, modifications to associated registry protocols and market conditions related to project types eligible for crediting under CARB protocols and revise protocols as necessary to ensure that offsets credits are real and additional and that uncertainty is accounted for in a conservative manner. (UCS6, UCS7)

> **Response:** Thank you for your comment. We agree that offset protocols must ensure that GHG reductions and GHG removal enhancements resulting from them meet the criteria listed by the commenters. We believe that the requirements for offset protocols in section 95972, along with our Compliance Offset Protocol stakeholder processes, will ensure that this is met. We did add language to state that Compliance Offset Protocols will be reviewed and periodically revised as needed.
>
> We believe that the Compliance Offset Protocols, in conjunction with all of the strict and thorough requirements in the regulation regarding offsets, meet the requirements of AB 32. Any Compliance Offset Protocols adopted under the cap-and-trade regulation will include multiple levels of review, use conservative methods to account for uncertainty and emissions leakage, and establish the additionality of offset projects in setting project baselines. To assure offset quality, the program includes rigorous oversight and audit procedures for all ARB-accredited offset verifiers, offset project developers, and Offset Project Registries. In addition, the registry system for compliance instruments is being designed to provide strong enforcement capabilities, including mechanisms to prevent double-counting, public disclosure requirements, and methods to clearly define ownership.
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> Generally, we do not include implementation-related procedures in our regulations. We plan to develop guidance documents related to the protocol approval process in 2012. In addition, all offset protocols used in the compliance program must be adopted by the Board after undergoing a full regulatory process, including an ARB stakeholder process, in accordance with the Administrative Procedure Act, and an environmental review. We plan to look at further offset protocols for potential inclusion in the cap-and-trade program beginning in 2012. The details surrounding any new offset project types for which ARB adopts an offset protocol will be dealt with in that rulemaking.

M-17. Comment: Add three new subsections to section 95972 or publish these procedures in an adopted procedures document:

<u>(d) Review of new protocols: All protocols adopted after January 2012 shall undergo a thorough review before adoption to ensure that each protocol meets the requirements established in 95972(a). This review shall include:</u>

(1) A review of research on emissions quantification and verification related to that project type;
(2) A study of the considerations facing existing and potential developers regarding the development or expansion of the project type(s) covered by the protocol.
(A) At a minimum, this study shall include:
1. interviews with potential developers of the project types included under the offset project protocol,
2. interviews with developers of some existing projects, if relevant, and
3. input from experts familiar with the considerations of developers of project type/s supported by the protocol;
(B) In conducting this study, the Board shall consider:
1. the factors that influence project development decisions of the project types that qualify under the protocol
2. the expected influence of offsets credits on those decisions;
3. the business-as-usual activities that are likely to go forward regardless of the ability to generate offsets credits; and
4. whether the business-as-usual reductions that are inadvertently credited under the protocol are counter-balanced by conservative methods to calculate emissions reductions.
(3) Review by one or more independent experts. At least one independent expert must have demonstrated expertise in the quantification of emissions reductions related to the project type;
(4) A timely opportunity for public comment on the review results.

add (e) Periodic review of all adopted protocols: All adopted protocols shall be reviewed, and revised if necessary, at least once every three years, or less frequently if the number of credits issued under a particular protocol is very small (CARB staff to decide on what this threshold should be) to ensure that it meets the requirements established in 95972(a). Each review shall include:
(1) Updating methods of calculating emissions reductions under the protocol when there have been substantial advances in research on emissions quantification related to that project type;
(2) A thorough review and evaluation of updates made to related registry protocols;
(3) A study of the considerations facing existing and potential developers of the project type/s covered by the protocol. At a minimum, this study shall include:
(A)input from experts familiar with the considerations of developers of project type/s supported by the protocol;
(B) interviews with existing and potential developers of projects of the project type/s covered under the protocol;
(4) Assessment of the extent to which the protocol has enabled additional emissions reductions or enhancements that would not otherwise have taken place without the offset protocol. This shall involve an analysis of the incentives that have been created through the offset program and whether those incentives

have been a significant factor in allowing for the development of or expansion of projects pursuant to the proposed protocol; and
(5) Assessment of the extent to which the protocol may have credited business-as-usual activities;
(6) Review by one or more independent experts. At least one independent expert must have demonstrated expertise in the quantification of emissions reductions related to the project type;
(7) A timely opportunity for public comment on the review results.

(f) Ongoing monitoring of protocols: protocols shall be monitored to ensure their consistency with the requirements of 95972(a). Protocols shall be revised when any of the following would result in substantial changes in the estimation of emissions reductions from offset projects:
(1) Research advancements on quantifying emissions reductions from protocol project types;
(2) Updates to related registry protocols that lead to more accurate or conservative measurement of emissions reductions;
(3) Significant changes in market conditions affecting the rate at which projects would be developed without the offset protocol; or
(4) Changes in the baseline. (UCS7)

Response: Thank you for your comment. Generally, we do not include implementation-related procedures in our regulations. We plan to develop guidance documents related to the protocol approval process in 2012. In addition, all offset protocols used in the compliance program must be adopted by the Board after undergoing a full regulatory process, including an ARB stakeholder process, in accordance with the Administrative Procedure Act, and an environmental review. We plan to look at further offset protocols for potential inclusion in the cap-and-trade program beginning in 2012. The details surrounding any new offset project types for which ARB adopts an offset protocol will be dealt with under that specific rulemaking, and modification will be made to the cap-and-trade regulation as needed.

We added new section 95971(b) which requires that all offset protocols will be reviewed and periodically revised if needed.

M-18. Comment: The Regulation should incorporate specific procedures for periodically reviewing existing protocols. Moreover, periodic reviews of existing protocols should assess the influence that the protocol has already had on new project development. (UCS6)

Response: We added new section 95971(b), which requires that all offset protocols will be reviewed and periodically revised if needed.

M-19. Comment: CARB should develop additional guidance for protocol development for use in the Cap and Trade program, in particular for use of modeling to calculate emissions reductions. EDF recommends that CARB provide additional clarification to inform project developers of the steps needed to bring new credit protocol ideas to the agency for consideration, development, and eventual adoption. Guidance on the use of models for calculating emissions reductions would be particularly useful since models are becoming increasingly accurate, yet complex, and are likely to take an active role in credit development for high quality agricultural projects in the future. (EDF4)

> **Response:** Thank you for your comment. Generally, we do not include implementation-related procedures in our regulations. We plan to develop guidance documents related to the protocol approval process in 2012. In addition, all offset protocols used in the compliance program must be adopted by the Board after undergoing a full regulatory process, including an ARB stakeholder process, in accordance with the Administrative Procedure Act, and an environmental review. We plan to look at further offset protocols for potential inclusion in the cap-and-trade program beginning in 2012. The details surrounding any new offset project types for which ARB adopts an offset protocol will be dealt with under that specific rulemaking, and modification will be made to the cap-and-trade regulation as needed.

M-20. (multiple comments)
Comment: Modify section 95972 as follows:
(a) To be approved by the Board, a Compliance Offset Protocol must:(1) ~~accurately determine~~ Conservatively estimate the extent to which GHG emission reductions or GHG removal enhancements are achieved by the offset project type; (UCS7)

Comment: (5) Conservatively account for uncertainty in quantification factors for the offset project type; (UCS7)

Comment: *Add:* (11) Ensure, with a high degree of confidence, that the total credits generated under the protocol will not exceed the total reductions and enhancements enabled by that protocol; (UCS7)

Comment: *Add:* (12) Ensure the project types that qualify under the protocol, absent being eligible as part of the compliance offset protocol, are not likely to be pursued, would be pursued at significantly lower rates, or result in reductions that are negligible in number; (UCS7)

Comment: Add: (13) Ensure the business-as-usual reductions that are inadvertently credited under the protocol are counter-balanced by conservative methods to calculate emissions reductions; (UCS7)

Comment: *Add:* (14) Ensure the project types that qualify under the protocol do not hinder the long term sustainability of the related sector, including the resilience and adaptability of agricultural systems. (UCS7)

Response: We did not include the exact language requested by the commenter in the regulation. We agree that offset protocols must ensure that GHG reductions and GHG removal enhancements resulting from them meet the criteria listed by the commenters. We believe that the requirements for offset protocols in section 95972, along with our Compliance Offset Protocol stakeholder processes, will ensure that these criteria are met.

In order to ensure that reductions or removals credited as offsets are real, the regulation requires that all Compliance Offset Protocols address activity-shifting and market-shifting leakage. Each protocol must account for leakage in the quantification of the reductions or removals achieved by the offset projects. In addition, when uncertainty exists in quantifying GHG reductions, we will only issue offset credits when there is a high level of confidence that reductions actually occurred. The regulation employs a principle of conservativeness in the quantification of emissions reductions. This method will ensure that the accounting will underestimate, rather than overestimate, any reductions when there is a high level of uncertainty.

In regard to additionality, we believe that the Compliance Offset Protocols, in conjunction with all of the strict and thorough requirements in the regulation regarding offsets, meet the requirements of AB 32. Any Compliance Offset Protocols adopted under the cap-and-trade regulation will undergo multiple levels of review, use conservative methods to account for uncertainty and emissions leakage, and establish the additionality of offset projects in setting project baselines.

M-21. Comment: *Add:* <u>(10) Use a baseline that reflects the most stringent combination of statutory and regulatory requirements between California and the jurisdiction where the offset project is located;</u> (UCS7)

Response: We intend to implement this policy through the adoption of each Compliance Offset Protocol and do not find it necessary to include language regarding this in the regulation itself. The decision to only include offset projects that qualify based on a regional additionality test throughout the WCI was made by the Partners to ensure that offset projects will be developed in WCI Partner jurisdictions and to ensure that a portion of the revenues generated from offsets would be generated in-state. WCI Partners do not want to create a program that pays parties in other states and provinces to undertake activities that they are requiring their sources to undertake by capping them or applying other direct regulations to such activities.

M-22. Comment: Some existing protocols simply prohibit (as an eligibility condition for use of the protocol) the conditions that pose a risk of leakage, and require the Offset Project Operator or Authorized Project Designee to demonstrate that these eligibility conditions are met. For example, ACR's Fertilizer Management protocol makes projects that increase fertilizer use outside the project boundary, or lead to decreases in yield, ineligible. As long as the Offset Project Operator or Authorized Project Designee can demonstrate to a verifier these conditions have been met, the risk of activity-shifting or market-shifting leakage exceeding de minimis levels is effectively eliminated. ACR recommends revising section 95972(a)(4) to read: "Account for activity-shifting leakage and market-shifting leakage for the offset project type, unless the Compliance Offset Protocol stipulates eligibility conditions for use of the protocol that eliminate the risk of activity-shifting leakage and/or market-shifting leakage exceeding de minimis levels as defined in the protocol;" (MARTINN3)

Response: We agree and added similar text to section 95972(a)(4).

M-23. Comment: While the Regulations provide extensive requirements for verification, if the program allows offsets based on subjective, speculative and unenforceable criteria, then verifiers cannot change this underlying flaw. In addition, verifiers have an incentive to validate the overall program, without which their employment would be unnecessary. (WILLIAMSZ2)

Response: We disagree that the offsets in our program do not provide real reductions. We believe that the Compliance Offset Protocols, in conjunction with all of the strict and thorough requirements in the regulation regarding offsets, meet AB 32 requirements and provide for prescriptive project development methods. The Compliance Offset Protocols adopted under the cap-and-trade regulation have been established with multiple levels of review, use conservative methods to account for uncertainty and emissions leakage, and establish the additionality of offset projects in setting project baselines.

The regulation proposes a robust monitoring program for offset projects—both the verification that the offsets are real, additional, and enforceable, and that Offset Project Operators, verifiers, and Offset Project Registries are operating according to regulatory requirements. In addition to the ARB audits, Offset Project Registries are required to conduct oversight of their registry program and randomly audit verifications to ensure that our regulatory requirements are being met by Offset Project Operators and verification bodies. We will provide rigorous oversight of our approved Offset Project Registries.

In addition, we designed our regulatory offset verification program to provide a transparent process by which we can review verification documents and fully understand any findings uncovered during the course of verification of an offset project by an ARB-accredited verification body. We will also develop an audit and oversight program for offset project verifications. All oversight functions are part of implementation and need not be specified in the regulation.

M-24. Comment: The Regulations repeatedly indicate that an important function of offsets is to keep the costs of compliance low and thereby prevent leakage of California's industry and attendant polluting activities to other jurisdictions, as well as to address other sectors of the economy not subject to the cap. Leakage of emissions is a significant concern. However, the potential for leakage to occur is not an excuse for adopting a fatally flawed and unworkable approach, such as Cap and Trade with greenhouse gas offsets. In addition, relying solely on compliance caps and offsets to reduce emissions, rather than an increase in prices, hurts many of the incentives that would drive the rapid transition to a clean-energy economy needed to avert dangerous climate change. For instance, if CARB were to adopt carbon fees that rise predictably to insure that clean energy will become cost-competitive with fossil fuels within a known time frame, this would create huge incentives for a shift in private investment from fossil fuel energy into clean energy infrastructure and innovation as well as in energy efficiency. Similarly, individuals and businesses would experience a strong incentive to be creative in reducing their carbon footprint. In this respect, the cost containment approach of greenhouse gas offsets is not only lacking in integrity but also undermines critical incentives needed to provide the rapid reductions without which costly and potentially irremediable effects of climate change are likely to become inevitable. As noted in the Scoping Plan, one way to address leakage is "border adjustments," adding costs to goods that arrive from jurisdictions whose regulations do not have programs to address greenhouse gases and rebating costs to goods that travel from California to other jurisdictions (see Supplement at p.92). While such border adjustments can be more easily imposed on international trade, it may be possible to impose such adjustments on interstate commerce as long as the adjustments merely create a level playing field for out of state businesses and are not protectionist. Essentially, CARB fails to acknowledge that higher prices for activities that produce greenhouse gases are an extremely valuable tool for driving greenhouse gas reductions. CARB instead claims that keeping costs low is a higher value, discarding the alternative as politically and legally untenable, rather than analyzing this alternative as required by the Superior Court decision and State law. (WILLIAMSZ2)

> **Response:** We do not agree the requirements of AB 32 have not been met regarding leakage. We designed the regulation to avoid unintended consequences. However, given the complexity of the program, it is important to incorporate systems to monitor and evaluate the performance of the cap-and-trade program. We propose to monitor emissions leakage, the generation and use of offset credits, and the potential for emissions increases, to ensure that the program continues to meet the diverse objectives described in Health and Safety Code sections 38562(b) and 38570(b) over time.
>
> AB 32 states that ARB must minimize leakage to the extent feasible. The cap-and-trade program is designed to minimize leakage to the extent feasible through the allocation strategy and the accounting for leakage, using a principle of conservativeness in the offsets program. Offsets are a small component of the cap-and-trade program, which is only one of the strategies that have been adopted to reduce statewide greenhouse gas emissions. The cap-and-trade program, together with the other complementary measures that have been adopted, meet the requirements of AB 32 in this area.

We disagree that the inclusion of offsets does not require capped sources to reduce emissions. The program imposes a limit on what we believe is an appropriate amount of offsets that an individual covered entity can use for compliance. All offsets used for compliance are real reductions, albeit outside the cap. Allowing a limited number of offsets into the program provides cost-containment benefits and ensures that some GHG emissions reductions occur within the sectors covered by the cap-and-trade program. The program includes provisions that would allow a maximum of 201 $MMTCO_2e$ of offsets through the year 2020. This limit will be enforced through a limit on the use of offsets by an individual entity equal to eight percent of its compliance obligation, or total emissions. Combined with the Allowance Price Containment Reserve, this limit ensures that emission reductions come from sources covered by the program at expected allowance prices, while use of the reserve will relax that constraint if prices rise.

The Scoping Plan FED provided several alternatives to the proposed regulation. That document identified the cap-and-trade program as the best option to reduce GHG emissions and meet the additional mandates of AB 32, including cost effectiveness and certainty of meeting the 2020 GHG emissions target. The Staff Report also evaluated other options and concluded that the cap-and- trade regulation was the best option.

Offset Supply and Additional Offset Protocols

M-25. (multiple comments)
Comment: Since ARB may in the future approve additional Compliance Offset Protocols, ACR suggests adding section 95973(a)(2)(C)(5), "Reserved for additional Compliance Offset Protocols." (MARTINN3)

Comment: Since ARB may in the future approve additional Compliance Offset Protocols, ACR suggests adding section 95975(e)(5), "Reserved for additional Compliance Offset Protocols." (MARTINN3)

Comment: Since ARB may in the future approve additional Compliance Offset Protocols, ACR suggests adding section 95976(d)(5), "Reserved for additional Compliance Offset Protocols." (MARTINN3)

Comment: A shortage of offsets threatens the viability of the entire program. Just as ARB's "no offset" model showed a huge increase in the cost of the program, a program with an anemic supply of offsets also will increase the costs to levels that would threaten the viability of the entire program. Yet ARB has not proposed to add any new compliance offset protocols nor added to the list of projects eligible for early action credit. We strongly recommend that ARB explore additional paths for generating offset credits. Of course, the best way to expedite the development of compliance offset protocols is to adapt the high quality ones that exist today in the voluntary market. We strongly encourage ARB to consider the protocols developed by such carbon project standards organizations as the Climate Action Reserve ("CAR"), the Verified Carbon Standard, the American Carbon Registry, and the Gold Standard. For new compliance protocols developed in this way, the projects developed in accordance with the forerunner voluntary protocols ought to be made eligible for early action credit—as is now the case with ARB's four existing compliance protocols. Not to do so would violate AB 32's mandate that "appropriate credit" be given to voluntary early actions. Cal. Health & Safety Code section 38562(b)(3). (COPC3)

Comment: I recommend that ARB expand the list of eligible protocols so that the supply of offset credits issued under the ARB-approved protocols are more capable of meeting demand. More clarity must be provided for how early action protocols can be brought forward for consideration and approval. (GRINNELL)

Comment: CLFP encourages CARB to address offset supply options by accepting energy efficiency projects as an approved offset. (CALFP3)

Comment: CARB recognized in the Scoping Plan that increasing the energy efficiency of existing buildings provides the "greatest potential for GHG reductions in the building sector." CARB's Scoping Plan urges "adopting mechanisms to encourage and require retrofits for existing buildings that do not meet minimum standards of performance." NAIMA urges CARB to broaden its scope of acceptable offsets. Energy efficiency offsets should be added to the list of acceptable/approved offsets. Energy efficiency measures should be given top priority over renewable, where benefits tend to be uncertain, distant, and unpredictable. (NAIMA2)

Comment: CARB should weigh the significant environmental benefits offered by insulation products. Unlike other energy efficiency measures, such as energy efficient appliances or energy saving light bulbs, insulation, once installed, requires no additional energy to save energy. It not only provides significant economic benefits to the State, but it helps CARB meet its goal to reduce GHG emissions through increased efficiency. (NAIMA2)

Comment: Section 95973(a)(2): Additionality. We are concerned that, as described, the additionality requirements of offset credits may lead to unintended, perverse incentives. We seek clarity from CARB on how it intends to avoid creating such negative incentives, which we describe in greater detail below. If early adopters of agricultural conservation practices, which demonstrate reduced GHG emissions benefits, are prohibited from receiving offset credits, early adopters may choose to stop their use of those conservation practices so that they may, in the future, re-establish those practices to then qualify for offset credits. To avoid penalizing early adopters of beneficial practices and creating such perverse incentives, CARB should establish that additionality for agricultural offset protocols is determined by the common practice for the industry and should not include a fixed date requirement of when the practice was to be established on the operation. For example, the common practice for soil management for a particular crop may be the use of synthetic fertilizer applications. Those who rely on alternative soil management practices (e.g. compost, cover crops, reduced fertilizer use, etc.), which are above the common practice in terms of demonstrated GHG emission reduction benefits and meet the other offset protocol requirements, should be eligible for the offset credit, regardless of when they began their use of the alternative soil management practices. (CACAN3)

Comment: The marketplace tends toward simplified approaches to agricultural GHG mitigation—rewarding single practices rather than assessing and rewarding whole farming system approaches—which may not lead to overall GHG emission reductions. For example, altering some agricultural management practices to reduce GHG emissions may lead to changes in management practices elsewhere on the farm or ranch that could cause greater, unintended GHG emissions. To minimize the chance that agricultural offset credit protocols will fail to account for displaced GHG emissions within the agricultural operations, CARB should only adopt offset protocols that account for the full life cycle impacts of agricultural practices on the entire operation. (CACAN3)

Comment: To the extent that high quality protocols for emissions reductions that occur in disadvantaged communities can be developed, EDF recommends that CARB pursue them. (EDF4)

Comment: ARB has made no modifications to the draft Regulations regarding the four Climate Action Reserve (CAR) protocols used to classify compliance-eligible offsets and those eligible to receive early action credit. IETA has continued concerns limiting eligible offsets to these four project types alone would cause an immediate supply shortage. We believe there are simply not enough offsets presently available under these four protocols to provide the market with sufficient supply to effectively mitigate costs to California consumers. Additional paths for generating offset credits should be explored and incorporated into California's Cap and Trade program. These include the issuance of offset credits for projects using ARB-approved protocols, beyond the four identified. Emission reductions from all qualified existing CAR projects should be brought into the compliance system and become compliance eligible. In addition, ARB should consider recognizing protocols from other high-quality carbon project standards organizations, such as the Verified Carbon Standard, the American Carbon Registry, the Chicago Climate Exchange, and the Gold Standard. Recognizing existing projects will help to create a greater initial supply of offset credits for the market. In addition to expanding CAR offset limits and criteria, state officials must continue to consider how to practically link with external offset and allowance programs, including the Western Climate Initiative (WCI), the Regional Greenhouse Gas Initiative (RGGI), Clean Development Mechanism (CDM), and EU ETS. There is a great need for ARB to provide more clarity regarding additional project types that may become eligible for offset credit. Developing offsets is a long and complex process that requires significant investment. It can take years for new projects to become market ready. Considering the demand for offsets will only rise over time, giving project investors as much foresight as possible will help ensure adequate supply is available. In addition, IETA recommends ARB establish an open and defined mechanism through which offset project developers can propose new project types and methodologies for consideration.

At the moment, there is no formal path for introducing such methodologies and this would greatly streamline the process. (IETA3)

Comment: We encourage the Board to consider and adopt additional standardized, performance-based protocols that have been developed with broad stakeholder input and support as soon as possible. Doing so will allow sufficient time for offset projects to be built and operate so that they may begin providing a flow of offset credits into the program well before it launches. (CAR4)

Comment: We recommend that the Board consider and adopt each of the Reserve's high-quality offset protocols: Organic Waste Composting, Organic Waste Diversion, Nitric Acid Production, Landfill Methane Capture and Destruction, Coal Mine Methane, Destruction of Ozone Depleting Substances from Article 5 Countries, and Livestock and Landfill Methane Capture and Destruction for Mexico. The Reserve will shortly complete two additional protocols for the agricultural sector, Rice Cultivation and Nutrient Management. We also encourage the Board to consider and adopt these protocols as soon as they are completed. (CAR4)

Comment: CCSF strongly urges ARB to adopt offset protocols for composting and anaerobic digestion in the Cap and Trade program. Composting and anaerobic digestion projects are proven highly beneficial strategies that avoid the fugitive biogas releases from landfills. Further, the use of the compost produced by these strategies provides multiple greenhouse gas reduction benefits. Therefore, CCSF urges ARB to provide clear incentives for composting and anaerobic digestion over landfilling. (SFMAYOR3)

Comment: Offsets are an important component of compliance with AB 32. Given that the emission targets are very aggressive and require equipment that is technology-forcing, there is a danger that offsets will not be developed in sufficient quantity to provide the needed program flexibility. For example, we note that ARB has only approved a handful of protocols at this time, when there are eleven protocols that have been developed by the Climate Action Registry. Two key protocols, landfill gas for North America and coal mine methane have been developed and used by Climate Action Registry for several years recommend that these be considered by ARB in early 2012. The North America landfill gas protocol would add over 50 percent more offsets in the first compliance period. The coal mine methane protocol holds the potential to provide a large supply of valuable and verifiable offsets that could ensure that AB 32 emission reductions are achieved cost-effectively. (WSPA3)

Comment: CARB should adopt more high quality protocols for offset credit development and use in the Cap and Trade program, with emphasis on land-based greenhouse gas reductions. EDF recommends CARB staff identify high quality offset credit protocols and submit them for adoption by the board as soon as possible. Based on the multiple benefits that can be achieved by offsets, and the great potential to locate these projects in California, EDF recommends CARB staff prioritize high quality agricultural protocols for adoption in the Cap and Trade program. (EDF4)

Comment: CCSF supports expanding current programs and developing new regulations to further encourage reductions in natural gas consumption. Additionally, given the intensity and more immediate impact of emissions of high methane content biogas relative to carbon dioxide, CCSF urges ARB to develop offset protocols that encourage investment in facilities that capture and reduce methane emissions from landfills, wastewater treatment, and leakage from natural gas transmission lines. (SFMAYOR3)

Comment: Conversion technology facilities should have the ability to generate offsets in the proposed Cap and Trade system because they are reducing GHGE emissions from several sources, including a reduction in fossil-based electricity generation, transportation of waste, and deposition of waste in a landfill leading to methane emissions. Rather than excluding such facilities from being able to "sell, trade, give away, claim, or otherwise dispose of any of the carbon credits, carbon benefits, carbon emissions reductions, carbon offsets or allowances," ARB should encourage the development of protocols that would validate the GHGE reduction potential of conversion technologies and encourage development of conversion technologies within California. (CLADPW)

Comment: Promote innovation by allowing more flexibility in measurement of offsets. Impacts on innovation stimulated by offsets were frequently cited as a concern in developing offset policy. Offsets are a driver of innovation. This might occur through two pathways: First, use of offsets in uncapped sectors (e.g., agriculture and forestry in California) creates an incentive to innovate in areas that would not otherwise be reached by the carbon price signal under the cap. As emissions reductions from offsets lead to learning-by-doing, costs fall and the supply of offsets increases, providing further opportunities. Second, offset use in developing countries might not only contribute direct emissions reductions it could also serve as a vehicle for technology transfer. The technology diffusion process, kick-started with offsets, would contribute additional emissions reductions. (WSPA3)

Comment: CalChamber appreciates that the offset limit has been raised from 4 percent to 8 percent of a covered entity's compliance obligation. While we believe the extension of offset limitation is a step in the right direction, we believe that in order to reduce program costs, especially the high costs of a California-only program, a robust supply of offsets is required. Therefore, we encourage CARB to consider the inclusion of other offset protocols outside of the four protocols currently under consideration and to delegate authority for offset approval to capable third parties. We believe that a broad qualitative use of offsets is an important cost-containment mechanism within the cap-and-trade program. Geographic limitations will result in unnecessarily high compliance costs. For that reason CalChamber urges CARB to consider the inclusion of other offset protocols with linkage to existing offset programs, near term linkage to regional programs such as the Western Climate Initiative (WCI), and future linkage to a possible EU offset program as well. (CALCHAMBER3)

Comment: While PG&E understands that a separate rulemaking is required for additional offset protocols, PG&E is supportive of and encourages the speedy approval of additional protocols. Using the current data from the Climate Action Reserve's database, PG&E has updated its offset forecast. This forecast predicts that the four protocols under consideration by the ARB will generate approximately 15 million metric tons by the end of the first compliance period and approximately 30 million metric tons by the end of the second compliance period. PG&E reviewed the potential of the other Reserve protocols and the Nitric Acid Production, U.S. Landfill, and Article 5 Ozone Depleting Substances Protocols show the greatest potential to generate sufficient offset volume so that complying entities can use up to 8 percent offsets to meet their compliance obligation. PG&E also recommends that the ARB consider the American Carbon Registry's Conversion of High-Bleed Pneumatic Controllers in Oil & Natural Gas Systems and the Reserve's Coal Mine Methane, Organic Waste Digestion, and Organic Waste Composting Protocols as high quality protocols capable of generating robust volumes of offsets. (PGE4)

Comment: CCEEB recommends that ARB begin the process to delegate approval of offsets to third party registries and adopt new protocols rapidly to ensure that adequate supply is available in the first compliance period. Additional supply options should include the use of five additional Climate Action Reserve Protocols; use of offsets from Western Climate Initiative Partners; support the development of Pilot REDD Projects; use of Climate Action Reserve Landfill Credits generated before 2012; and approval of protocols developed by California air districts, as appropriate. (CCEEB3)

> **Response:** Any new protocols would be subject to new rulemaking process. ARB will be evaluating additional protocols in 2012. Responses to similar comments can be found in this category under the 45-day comment responses.

M-26. (multiple comments)
Comment: While they may be the preferred way to go, standardized approaches are limited in number, take time to develop, and require significant resources. Allowing project-based protocols to be approved for a limited time will encourage a diverse and creative range of protocol types over the longer term. Importantly, the development of project-based approaches can serve to inform the creation of standardized approaches in certain sectors and will provide the necessary incentives to motivate an industry-wide move towards lower carbon emissions. Restricting approved protocols to only standardized approaches could also result in insufficient offset supply arising from a limited set of protocols. ARB should specify that project-based approaches, like those used in many other offset programs around the world, will be accepted for a limited transition period at the beginning of the Cap and Trade program's implementation, and as a transition to sector-wide approaches. (VCSA)

Comment: The modified draft rule provides no formal path for submitting methodologies for review, evaluation and approval by ARB. An open, transparent process for reviewing, evaluating and approving offset methodologies is a necessary signal for the market to continue developing protocols (and projects) that will provide the offsets necessary for effective cost-abatement. ARB should establish an open and defined mechanism through which offset project developers can submit new project types and methodologies for consideration. VCSA suggests that ARB consider adopting a process similar to that employed by the Australian Department of Climate Change and Energy Efficiency for inviting parties to submit methodologies for review and approval under that country's forthcoming Carbon Farming Initiative. Details about that submission process can be found at http://www.climatechange.gov.au/government/initiatives/carbon-farming-initative/methodology-development/methodology-guidelines.aspx. (VCSA)

> **Response:** New protocols will be developed as part of new rulemaking, and staff will be evaluating new protocols in 2012 through a public process. The program has been designed to develop standardized protocols to ensure consistency across project types. Project-based protocols would be labor intensive, as each protocol would be a separate rulemaking. Staff will be developing documentation on the process for protocol review and development as part of program implementation. Responses to similar comments can be found in this category under the 45-day comment responses.

M-27. Comment: The offset market will be a key component of the State's carbon management strategy. However, the lack of approved protocols, coupled with the new stringent liability restrictions that CARB has proposed, will stifle this market to the extent that its function as a "cost containment measure" will be meaningless. We urge CARB to reduce the self-imposed barriers to this environmentally-beneficial mechanism by approving more protocols, eliminating the buyer-liability component, and allowing greater than 8 percent of a sources' allowance obligation to be met through the use of offsets. (VALERO2)

> **Response:** In regard to the adoption of additional protocols, this comment falls outside the scope of the First 15-Day Changes Notice. Responses to similar comments can be found in this category under the 45-day comment responses. Because the comment falls outside the scope of the notice, no further response is required.
>
> We did not increase the amount of offsets allowed to be used in the program. The program imposes a limit on the amount of offsets that an individual covered entity can use for compliance. All offsets used for compliance are real reductions, albeit outside the cap. Allowing a limited number of offsets into the program provides cost-containment benefits and ensures that some GHG emissions reductions occur within the sectors covered by the cap-and-trade program. This limit will be enforced through a limit on the use of offsets by an individual entity equal to eight percent of its compliance obligation. Combined with the Allowance Price Containment Reserve, this limit ensures that a majority of reductions from the program come from sources covered by the program at expected allowance prices, while use of the reserve will relax that constraint if prices rise.

We do not agree that we should eliminate buyer liability associated with the invalidation of ARB offset credits. Requiring the user to replace the invalidated offsets ensures that purchasers and users of offset credits do their due diligence in seeking out high-quality offset credits. We have clear enforcement authority over covered entities that will be using ARB offsets for compliance. If the covered entity replaces any invalidated offset credits, they may then take appropriate action through third-party contractual arrangements that they may have established prior to purchase. These arrangements currently exist in the voluntary offset market, and we expect that as the offset market becomes more established that additional mechanisms to deal with the risk of invalidation will also be established. In the event that the offset credit has not yet been used or retired, it will be canceled in the market tracking system and removed from any Holding or Compliance Accounts. These provisions in no way diminish our authority to assess penalties under section 96014 on any offset project developer or verifier that has provided false information to ARB.

M-28. Comment: We encourage ARB to take expedited action separate from this 15-day package to finalize new protocols. Such new protocols will be crucial for ensuring sufficient supply of offsets in the cap-and-trade system.

To this end, and in order to facilitate planning, CERP requests that ARB make additional information on the schedule for consideration of new offset protocols public. It would be helpful if ARB announces a date for the offset workshop on new protocols, and signals when those engaged in the market can look forward to seeing such new protocols introduced.

CERP stresses that offset projects take significant time to complete and therefore new offset protocols must be introduced as early as possible so that project development may begin in a timely manner and offset credits may begin to be generated. The need for timely introduction of protocols is especially great because the Western Climate Initiative (WCI) has issued draft guidance that, if finalized, will require a new protocol to go through public comment processes both on the WCI level and in individual member jurisdictions, which will be extremely time-consuming and generally uncertain. The disclosure of further information regarding ARB's process and timing is especially important to project developers who are trying to determine whether to invest significant capital in new project types and who need signals concerning what protocols will likely be accepted and able to earn ARB credits.

Even if ARB can only provide a tentative indication of protocols under consideration, such a message can be helpful. The market is comfortable making advance investments around such conditional information.

CERP also requests that ARB make additional information public concerning the process and proposed timeline for setting up the offsets registry and the accreditation of verifiers, as well as the listing of offset projects. It is our understanding that many of these activities will be occurring during 2012 as the cap-and-trade system gets up and running, but before the compliance obligation begins in 2013. Any new information that ARB can provide the public with regard to their process for offset system development will be helpful in preparing the cap-and-trade market to begin operation. (CERP4)

> **Response:** In regard to the adoption of additional protocols, this comment falls outside the scope of the First 15-Day Changes Notice. Responses to similar comments can be found in this category under the 45-day comment responses. Because the comment falls outside the scope of the notice, no further response is required.
>
> We have provided a role for Offset Project Registries (OPR) to perform some of the administrative functions of the offset process in the regulation. We plan to utilize OPRs in lieu of having ARB perform these duties, and may choose to continue this approach throughout the program. We have not yet determined if and when we would perform these roles. Therefore, in the meantime, all parties seeking to use Compliance Offset Protocols must go directly to an OPR to list their projects. We are in the process of developing the training for OPRs and plan to approve OPRs sometime in 2012.
>
> In addition, we are in the process of developing the training for offset verifiers and plan to accredit offset verifiers in 2012 as well.

M-29.
Comment: Further consideration should be given to the need for robust offset supply. As more offsets become available, the probability that the reserve pool would be accessed drops significantly. As the allowed use of offsets goes down, the chance the reserve pool will be accessed goes up. We found that at the proposed 8 percent quantitative limit for using offsets, there is a 15 percent chance the reserve pool will be accessed; at a 4 percent quantitative limit for using offsets, there is an 89 percent chance the reserve pool will be accessed; and if no offsets are allowed in the program, the proposed allowance reserve is not likely to be sufficient to keep prices below $40 per ton. Also, since the reserve pool is populated with emissions allowances from future compliance periods and offsets are composed of present day reductions (or vintage reductions having occurred in the past), avoiding the use of the allowance pool (due in part to offsets availability) can be seen as achieving present day program benefits from current actions rather than as promises of actions yet taken. (EDF4)

> **Response:** We do not agree that there will be insufficient offset supply in the first compliance period. We estimate that if every entity used their allowable eight percent offsets, approximately 26 million metric tons of offsets would be needed in the first compliance period. This reduced need is due to a start of the first compliance period in 2013 instead of 2012. At this time, based on the four offset protocols the Board has endorsed—manure digesters, forestry, urban forestry, and destruction of ozone depleting substances—we will be close to the

supply demand for the first compliance period. We also will be looking to propose additional Compliance Offset Protocols beginning in 2012.

The program imposes a limit on the amount of offsets that an individual covered entity can use for compliance. All offsets used for compliance are real reductions, albeit outside the cap. Allowing a limited number of offsets into the program provides cost-containment benefits and ensures that some GHG emissions reductions occur within the sectors covered by the cap-and-trade program. This limit will be enforced through a limit on the use of offsets by an individual entity equal to eight percent of its compliance obligation. Combined with the Allowance Price Containment Reserve, this limit ensures that a majority of reductions from the program come from sources covered by the program at expected allowance prices, while use of the reserve will relax that constraint if prices rise.

Offset Project Registries

Registry Approval Process and Requirements

M-30. (multiple comments)
Comment: To ensure the integrity of all registry offset credits, provide proper oversight of the third-party verification process, identify and correct errors in offset project documentation, and minimize the risk of offset invalidations, we recommend that ARB approve only Offset Project Registries with significant technical expertise and years of experience conducting similar functions in the voluntary market. (MARTINN3)

Comment: The Board must therefore ensure that the registries participating in ARB offset generation have the expertise needed to perform this role and that they are performing their oversight tasks adequately. In addition to reviewing the performance of verifiers and verification bodies directly, CARB must also review the performance of the registries in conducting their oversight tasks. CARB must use discretion in approving registries. (UCS7)

Comment: Given the complexity and necessary knowledge required for these tasks, require that entities seeking to provide offset registry services for the regulatory cap-and-trade program have at least three years of demonstrated experience in operating a registry before they can be accredited, and establish competency requirements for registries equivalent to or better than those required for verification bodies. The draft regulation requires that verification bodies have experience before they may be accredited, but does not impose similar requirements for the registries that are meant to provide the first-level oversight of those verifiers. The competency requirements for staff at an offset registry (section 95986(c)(1)) should either be the same as, or stricter than, the competency requirements for staff at accredited verification bodies (specified in Title 17 at section 95132), since offset registries are required to check the work of the verification bodies through Offset Project Data Report review and verification audits. (CAR4)

Comment: EDF believes that having multiple high-quality offset registries operating with the Cap and Trade program will benefit the program as a whole. However, we caution against allowing sub-standard registries into the program or creating a system where credit developers can go registry shopping to find lax rules or less than rigorous registry oversight. As registries are allowed to participate, CARB must be careful to ensure they meet the highest standards for competence and do not possess conflicts which may undermine their ability to perform their designated market function with impartiality and objectivity. The Executive Officer and CARB staff should perform an up-front analysis of whether the registry meets the necessary provisions to be included in the program, including review of staff competence, experience and internal procedures. CARB needs to apply rigorous conflict of interest principles to registries. Registries should not be allowed to have a financial stake in the projects they accredit, especially if that stake has the potential to impact registry impartiality. Registries should perform a market function without acting as a market participant. (EDF4)

Comment: We believe that it is reasonable to include in the Regulation that all registry management and all registry staff complete training and pass an examination in not only all Compliance Offset Protocols, but also complete ARB approved general verification training and pass an examination (sections 95986(h) and 95986(i)). (FIRSTENVIRON3)

> **Response:** The regulation requires that we will only approve registries that meet a high standard under the regulation. The registry staff will be required to demonstrate practical knowledge of the protocols approved by the Board. The regulation contains requirements for regular information sharing between the registries and ARB. The regulation allows for ARB to request information or discussions with registry staff at any point. As with many of ARB's regulations, compliance training will be available, and in this case required, to ensure the highest qualified personnel are on staff at the registries.

M-31. Comment: Section 95986(j) provides for the approval of an entities' application to be an Offset Project Registry only after the applicant's management staff have completed the ARB training required in section 95986(h). Requiring applicants to undergo training before they are approved (or not approved) imposes an unnecessary expense and time burden on them. Since it is likely that an application will be rejected on other, more substantive grounds, we make the following recommendation. Revise the application review and approval process outlined in section 95986 that directs the Executive Officer to make a contingent approval of an applicant that meets the requirements defined in section 95986(c) through (g), with final approval subject to the applicant providing evidence that it has successfully completed the training requirement. Upon determining that an applicant meets requirements 95986(c)-(g), the Executive Officer would then notify the applicant of its contingent approval and provide a specified timeframe within which the applicant must successfully complete the training in order to receive final approval. Once the applicant provides evidence that it has successfully completed the training, the Executive Officer would then issue a final approval. (VCSA)

> **Response:** We did not make this change. The regulation requires that we will only approve registries that meet a high standard under the regulation. The registry staff will be required to demonstrate practical knowledge of the protocols approved by the Board. The regulation contains requirements for regular information sharing between the registries and ARB. The regulation allows for ARB to request information or discussions with registry staff at any point. As with many of ARB's regulations, compliance training will be available, and in this case required, to ensure the highest qualified personnel are on staff at the registries.

M-32. (multiple comments)
Comment: To maintain program integrity, registries must be free of real and perceived conflicts of interest. The prior version of the Regulation made it clear that for a registry to be accredited by the Board; its primary function must be operating an offsets registry. However, the revised Regulation now would allow any entity to designate a subdivision to provide registry services. If such entities provide other services in addition to registry functions, then they too must be free of conflicts of interest, including not being permitted to provide consulting services to offset projects, verifiers, or others involved in the carbon market. Remove the language at sections 95986(c)(2)(F) and 95986(d)(3) allowing 'subdivisions' of larger entities to be accredited, or modify the Regulation to prohibit such entities from providing consulting services to project developers, verifiers, compliance entities, and other affiliated organizations in order to avoid real or perceived conflicts of interest. (CAR4)

Comment: Section 95986(c) allows subdivisions of parent companies to act as registries. A potential unrestricted conflict of interest may arise under the rule because consulting services are not included in the list of prohibited activities in section 95986(d)(3). Accordingly, CARB will need to be extremely careful when reviewing subdivision registries and evaluating walling off procedures in place to ensure complete impartiality by the subdivision registry is retained. In the alternative, CARB could add consulting to the list of prohibited activities within section 95986. (EDF4)

> **Response:** Section 95986(c)(2)(F) was modified to clarify that the prohibition for serving as an offset project consultant applies at the subdivision level for those applicants that have designated a subdivision to provide registry services. In addition, registries must submit conflict-of-interest information to ARB, and we have the authority to revoke or suspend the approval of registries that violate the conditions in the regulation.

M-33. Comment: The revised Regulation appears to require the Executive Officer to accredit any entity that seeks to provide registry services so long as it meets the Board's minimal criteria (section 95986(j)(3)), though this appears to be inconsistent with the language at section 95986(b), that may provide more discretion. Such an approach could potentially lead to a proliferation of registries of variable quality and integrity. We recommend that the Executive Officer fully evaluate the procedures, operations, and capabilities of each Offset Project Registry to determine whether they are adequate to ensure that all offset credits issued meet the requirements of the

Regulation. Further, the Executive Officer should be provided the authority to not approve additional registries if it is determined that a sufficient number have been accredited to serve the program's needs. Limiting the total number of accredited registries will also serve to minimize the potential for errors and reduce the resource burden on the Board staff in overseeing such entities and their activities. (CAR4)

> **Response:** We did not make this change. If the requirements of this section are met, we must approve the applicant. We cannot pick and choose which programs to approve and which to deny, as long as all the requirements of the regulation are met.

M-34. Comment: Given the central role that registries play in ensuring the environmental and financial integrity of an emissions reduction and trading program, it is important that the providers of registry services are themselves technically capable, financially sound, and managerially competent entities. VCSA believes that the requirements for Offset Project Registries outlined in the proposed rule are not robust enough for purposes of establishing the sound, long-term functioning of the offsets program. For its own program, the VCSA requires its registry service providers to meet strict financial standing requirements (including, for example, more extensive insurance coverage than required by ARB and minimum net asset requirements), and have in place insolvency protections and conflict of interest policies (including prohibitions on proprietary trading of carbon instruments) that go beyond the requirements indicated in the modified draft rule. We suggest that ARB establish similar standards. Amend section 95986(c) to include requirements that Offset Project Registry applicants meet more robust financial standing standards similar to those established by VCSA for its registry service providers. As its agreements with its registry service providers are confidential, VCSA would be willing to share more details on these requirements with ARB as long as that confidentiality can be preserved. (VCSA)

> Response: We agree and added similar criteria to the regulation in sections 95986(c)(2)(A)(3.) and (d)(1).

Registry Services

M-35. Comment: We do have a concern that the requirement in section 95987(e)(3), may be difficult to achieve in the early years when there are relatively few projects. ACR recommends adding flexibility to this language in the event that, for example, the majority of the projects registered on a given Offset Project Registry happened to be clustered geographically, or by project type, or be mostly verified by the same body. (MARTINN3)

> **Response:** We did not make any change to the regulation in this area and consider this part of program implementation. We will work closely with registries to ensure that they develop audit plans that meet the regulation's requirements.

M-36. (multiple comments)
Comment: Section 95987(e) has been changed to require ten percent of the annual offset verifications to be audited by a registry. The version adopted in December 2010 had 20 percent offset verifications. Since offset quality is critical to program success, we would recommend keeping the higher audit requirement. (SCAQMD4)

Comment: CAPCOA believes the handling of offsets in the Cap and Trade program will significantly affect the success of the program, and we continue to support the use of only the highest quality verified offsets. We recommend that ARB continue to require that 20 percent of the annual offset verifications be audited by a registry, rather than the lesser amount (10 percent) proposed in the 15-day changes. (CAPCOA2)

> **Response:** We did not make this change. We changed the number of in-person audits that Offset Project Registries must perform from 20 percent to 10 percent because we will also have the audit program, which will include in-person audits in addition to those performed by Offset Project Registries. We will also have access to the audit results collected by Offset Project Registries. We believe that this approach will ensure rigor in the program and that it sets an appropriate level of audits.

M-37. Comment: To ensure the integrity of registry offset credits and to help identify problems or misstatements with projects before registry offset credits become eligible as ARB offset credits (and thereby reduce the risk of credits being invalidated later), we strongly recommend that offset registries not be limited in their responsibilities to only checking that verification reports are complete (section 95977.1(b)(3)(R)(4)(a)). Registries should also be required to review the substance of those reports for accuracy, just as the Reserve does with every project in its system today. Requiring this type of quality assurance and control will provide the Board with an important security step in the approval process. The Reserve does not issue credits without a significant level of review and oversight of verification reports and the Board should similarly require that offset registries provide this level of strict quality assurance before a credit can be considered as an ARB offset credit. (CAR4)

> **Response:** We agree and added a new provision that requires registries to check for completeness and to ensure that the regulation's requirements are met.

M-38. (multiple comments)
Comment: Clarification of registry duties for quality control and assurance of project documents is needed in section 95977. The new language requires that registries evaluate statements for "completeness and to ensure it meets the requirements of section 95977.1(b)(3)(R)(4)(a)." In section 95977.1, requirements include submission of an Offset Verification Plan, the detailed comparison of the data checks, the issues log, any qualifying comments on findings, and calculations performed in section 95977.1(b)(3)(Q). However, the changes do not yet make it clear what registries must do to evaluate this information for accuracy or to make sure the required boxes are

checked and paperwork is filed without regard to the accuracy of the information included in it. (EDF4)

Comment: We request that ARB clarify in section 95987(f) what is meant by report "completeness." We believe this term is subject to differing interpretation which could affect the quality and consistency of the required review. (FIRSTENVIRON3)

> **Response:** Offset Project Registries must ensure that the information submitted meets the regulation's requirements before accepting it from the verifier or Offset Project Operator or Authorized Project Designee. We will conduct training for Offset Project Registries so they will be equipped to interpret the regulatory requirements.

M-39. Comment: Modify section 95987(b) as follows:

> (b) The Offset Project Registry must make the following information publicly available for each offset project:
> (2) within 10 working days of the Offset Project Data Report being issued an Offset Verification Statement:
> add: <u>(F) Offset Project Data Report for each year the Offset Project Data Report was verified. Confidential information shall be treated as per section 96021</u> (UCS7)

> **Response:** We did not make this change. We will establish a minimum list of information for each project data report that will be made publically available for each project type as part of program implementation. This standardized approach will provide consistency across the program and ensure that confidential data is protected.

M-40. Comment: IETA is unconvinced that offset project registries can provide a workable insurance pathway. First, as ARB's own regulations recognize, registries themselves could be the source of a credit discrepancy. Second, registries are not well capitalized, and therefore could not be relied upon to pay out on claims. (IETA3)

> **Response:** While we included provisions allowing Offset Project Registries to provide an insurance mechanism against invalidations, the regulation does not require any parties to offer or use the insurance. It remains optional.

M-41. Comment: Regarding section 95987(e)(1), we assert that checks (B) and (C) are neither necessary nor appropriate for determining whether offset project verification was performed consistent with requirements of the regulation and request these clauses be removed from the Regulation. (FIRSTENVIRON3)

Comment: We feel that the check in section 95987(e)(1)(F)(1) is unnecessary since the verification body has already attested to this information per section 95979(e)(3)(F) and request these clauses be removed from the Regulation. (FIRSTENVIRON3)

Response: We did not make these changes. All of the requirements in section 95987(e) are part of oversight of the verification program and provide information to ensure that the program is functioning properly.

M-42. Comment: Section 95987(d) provides no timeline for registries giving guidance. Guidance should also be made public to improve transparency. The Climate Action Reserve now makes such guidance public and guidance is made public in other programs such as the CDM. Public guidance also helps developers to anticipate what changes will be incorporated in future protocol versions and prepare for them. It reduces duplication of effort where multiple project developers may ask for similar guidance. (CIG2)

Response: Section 95987 specifies that an Offset Project Registry may seek clarity from ARB before providing guidance to offset verifiers and Offset Project Operators. In addition, the regulation requires that Offset Project Registries submit a monthly report to ARB regarding the guidance they have provided. We will then make this information available on a publicly accessible website, so that verifiers and project operators can consult this guidance without having to request it from the Offset Project Registry. We believe that we will be in constant contact with the registries and do not anticipate a problem in this regard.

ARB vs. Offset Project Registry Roles

M-43. Comment: Offset Project Registry Requirements. We appreciate that the regulations lay out requirements for new registries. We however do not think that the language in section 95987 (f) is adequately clear or rigorous for ensuring that interpretation and implementation of these highly technical and complex protocols offset are consistent across registries. We recommend that ARB create a central repository and publically available site for answers to questions on how to interpret specific aspects of the protocol; that ARB clearly identifies itself as the final arbiter of disagreements or questions over interpretation; and that ARB actively ensures that consistent interpretation is being applied. (PFT3)

Response: Section 95987 specifies that an Offset Project Registry may seek clarity from ARB before providing guidance to offset verifiers and Offset Project Operators. In addition, the regulation requires that Offset Project Registries submit a monthly report to ARB regarding the guidance they have provided. We will then make this information available on a publicly accessible website, so that verifiers and project operators can consult this guidance without having to request it from the Offset Project Registry. We believe that we will be in constant contact with the registries and do not anticipate a problem in this regard.

Also, the regulation ensures that we will only approve registries that meet a high standard under the regulation. The registry staff will be required to demonstrate practical knowledge of the protocols approved by the Board and the compliance offset program.

Monitoring, Reporting, and Record Retention Requirements

General Monitoring Comments

M-44. (multiple comments)
Comment: Section 95976(a) requires meters to be maintained and calibrated at a frequency required by the manufacturer. However, the Livestock Protocol states that meters may be calibrated more frequently than manufacturers' recommendations and requires more frequent inspections. This is confusing. Which document should a developer follow? We believe that protocol-specific requirements should be left in the protocols, and not put in regulations. ARB staff should review the Regulations to make sure that there are no contradictions between what the Regulations prescribe and what the protocols prescribe. (CIG2)

Comment: In a number of instances, the main regulations and the individual protocols impose overlapping but different verification requirements that are particular to a specific offset project types. For example, section 95976(a) provides that meters for livestock offset projects be maintained and calibrated at a frequency required by the manufacturer. However, the Livestock Offset Protocol states that meters may be calibrated more frequently than manufacturers' recommendations; in addition, the protocol requires more frequent inspections. This type of confusion between the main regulations and the protocol could have significant adverse impacts on the program by leading to delays and disputes. In particular, these discontinuities could result in significant disarray if ARB continues to require invalidation of all offset credits from a data report if it is not "accurate." We recommend that protocol-specific requirements be left in the protocol, and not addressed separately and different in the main regulations. We urge ARB to review the regulations to identify and eliminate overlapping provisions. (CERP4)

> **Response:** We agree and clarified the language to say "unless otherwise specified in a Compliance Offset Protocol."

Interim Data Collection Procedures and Variances

M-45. Comment: It is not obvious how to make "A demonstration that no feasible alternative procedure exists that would provide more accurate emissions data." As written in section 95976(f)(2)(D), this requirement assumes knowledge of all possible data collection procedures, from which one could make feasibility determinations for the case at hand. Modify section 95976(f)(2)(D) as follows:

> (D) A demonstration that ~~no feasible alternative procedure exists that would provide more accurate emissions data~~<u>the proposed data collection procedure is conservative; that is, the proposed data collection procedure and any accompanying calculation methods will necessarily result in fewer verifiable emission reductions than the standard data collection method would have</u>

provided given identical project performance. (TPI5)

Response: These requirements have already been successfully implemented under the MRR. The offset project developer must conduct due diligence in proposing an interim data collection method. This requirement ensures that they explore several alternatives and not just the easiest one before proposing a particular one to ARB.

Record Retention Requirements for Offset Project Operators and Offset Verifiers

M-46. (multiple comments)
Comment: The OWG agrees with ARB's change to the records retention requirement which was reduced to 15 years from the previous 100-year requirement. The longer requirement was unreasonable and unnecessarily burdensome and the OWG appreciates ARB's recognition of this. However, in light of ARB's 8-year statute of limitations for invalidating offset credits, the OWG requests ARB to explain the necessity for having a retention requirement that is longer than the relevant statute of limitations. (OFFSETSWG3)

Comment: Section 95976 of the regulation sets out record retention requirements. Clearly a sequestration project could be allowed to establish a final crediting period baseline plus all offsets credits registered and then enter a monitoring process that would not require maintenance of all the preceding decades of documents. Of course during the active crediting period these records are necessary, but once in the monitoring period, with no additional revenue cost is an important issue. (CFA2)

Response: The record retention requirements in section 95976(e)(2) were changed to 15 years following the issuance of ARB offset credits due to stakeholder concerns about an unnecessarily long record retention requirement for forestry projects. Verifiers are also required to retain related documents for 15 years. The record retention requirements must be extensive enough for verification of each Offset Project Data Report. This provision is necessary to ensure that ARB or an OPR will have enough data to confirm that the crediting project has been operating in accordance with the appropriate ARB-approved protocol. These records may have additional enforcement uses, such as establishing a pattern of behavior. The invalidation time limit is independent of any other enforcement activities ARB may need to pursue.

Reporting and Verification Deadlines

M-47. Comment: Sections 95976 and 95977(d) provide a very strict delivery date for offset verification and offset project data reports. The penalty for being late is denial of eligibility of the offset credits reported in that Offset Project Data Report. This seems highly punitive especially given that many projects will have multiple years of data verified in the first report and if necessary to avoid this penalty just wait another year and submit this first Offset Project Data Report without any penalty. Especially in the first few years such deadlines should be more flexible to allow verifiers to get up to speed and ARB to have a steady flow of offsets arriving to keep Cap and Trade economic impacts down. (CFA2)

> **Response:** Section 95976(d) was modified to address stakeholder concerns about a calendar year reporting period with a fixed annual "verification period." The new requirements cover a reporting period that is not tied to the calendar year to address these stakeholder concerns. Additional modifications were made to the timing for the schedule for verification (sections 95977(b) and (c)) and the submittal of Offset Verification Statements (section 95977(d)) to be consistent with the new offset reporting schedule in section 95976(d) and clarify the verification cycle. The new cycle requires that Offset Project Data Reports be submitted to ARB within four months after the conclusion of the Reporting Period. They subsequently have to be verified within nine months after the conclusion of the Reporting Period. We believe the new requirements provide sufficient flexibility to meet the deadlines. For example, if a project developer completes their reporting within two months, they have seven months to get their Offset Project Data Report verified.

M-48. Comment: Though CERP appreciates the more reasonable period in the revised regulations for submitting reports, the requirement in section 95977(d) that states a project will not be eligible for registry offset credits if the deadline is missed is far too harsh a response when there may be a good faith reason for delay. For this reason, CERP urges ARB to include in the regulations a provision authorizing the agency to provide deadline extensions on the basis of specified reasons. Such reasons could include:

- A verification is delayed because the verifier is working on too many projects.
- A verification is delayed because the relevant Offset Project Registry loses its approval and the project must switch to another registry.
- A contracted verifier ceases to provide verification services.
- A verifier determines that a qualified positive verification statement is likely appropriate but will require consultation with ARB or the approved offset registry and/or the collection of further data to support the qualified positive verification statement.
- Data that must be submitted in an Offset Project Data Report must be obtained from a third party and the third party (or the third party's equipment) is responsible for the delay (e.g., meter malfunction).
- A verifier determines that additional data must be collected to meet important data quality standards (e.g. delays due to additional or repeated sampling of plots in a forestry project to improve statistical confidence).
- A decision by ARB or an Offset Project Registry is appealed by an Offset Project Operator or a verifier.
- A decision by a verifier is appealed by an Offset Project Operator.
- A verifier or an Offset Project Operator requires clarification on a protocol or its applicability to a specific project from ARB or an approved offset project registry.

- Project data collection or required verification site visits are delayed because the project site cannot be accessed (e.g. due to inclement weather) or because data collection equipment must be repaired or replaced. (CERP4)

  Response: We previously changed the reporting deadlines to an annual reporting cycle instead of a calendar-date deadline. We believe that this creates enough time for verification to occur, so extensions to the deadline in the regulation are unnecessary.

Verification

General Verification Comments

M-49. Comment: Section 95977.1(b)(3)(E) references a review of the GHG emissions inventory which we do not believe is intended in this section on offset verification services and request that the language be removed from the regulation. (FIRSTENVIRON3)

> **Response:** We agree and made this change.

M-50. Comment: We request that the language in sections 95977.1(b)(3)(D)(2)(f) and 95977.1(b)(3)(D)(2)(h), very clearly and explicitly identify what is required relative to these assessments as similar regulatory reviews under voluntary programs have lacked clear guidance regarding this issue. (FIRSTENVIRON3)

> **Response:** We did not make any changes to the regulation, but plan to provide guidance on how a verification body can conduct reviews, to ensure that these requirements are met.

M-51. Comment: We believe it is unclear in section 95977.1(b)(3)(L)(4) what is meant by “any discrepancies must be investigated” in this context and request that the language be revised to “any discrepancies must be identified.” (FIRSTENVIRON3)

> **Response:** We agree and made this change.

M-52. Comment: Please provide clarification on section 95977.1(b)(3)(M) regarding what is meant by “make any possible improvements or corrections to the submitted Offset Project Data Report.” What could be considered “possible” could be subject to different interpretations. (FIRSTENVIRON3)

> **Response:** This comment requires no change to the regulation itself. We will provide training to verifiers on how to provide services to ensure that the regulatory requirements are met.

M-53. Comment: Page A-205 (b)(3)(D) Site Visits for Offset Projects. It is unclear whether projects can register ARB credits based on less intensive verification opinions occurring between 6-year site visits. We request that it be clarified that credits can be issued based on optional Less Intensive Verifications occurring in intervening years when no site verification occurs. (BLUESOURCE2)

> **Response:** Less intensive verification allows desk reviews to be performed in the interim years that full offset verification services are not provided. We have maintained the requirement for site verification every six years and by including less intensive verification requirements, registry offset credits and ARB offset credits may be issued in the interim years if they meet the requirements of the regulation and the protocol.

M-54. Comment: The adoption of a "less intensive verification" in section 95977.1(b)(3)(D) is critical for sequestration projects facing excessive verification costs. However, it is not defined in the Regulation. We recommend that this term be defined in the Regulation and that the definition explicitly state that ARB Offset Credits can be issued upon the submission of a non-qualified less intensive verification opinion. (FINITE)

> **Response:** The term "less intensive verification" is defined in section 95802 of the regulation. Less intensive verification allows desk reviews to be performed in the interim years that full offset verification services are not provided. We have maintained the requirement for site verification every six years and by including less intensive verification requirements, registry offset credits and ARB offset credits may be issued in the interim years if they meet the requirements of the regulation and the protocol.

M-55. Comment: We request that section 95977.1(b)(1)(C) be revised to specifically identify what is meant by "documentation that the offset verification team has the skills required to provide offset verification services." (FIRSTENVIRON3)

> **Response:** We did not make this change. It is clear in the regulation that the offset verification team must have an offset project specialist on the verification team for the project type for which it is providing offset verification services.

M-56. Comment: While the intent of section 95977.1(b)(3)(G)(2) is clear within the context of an emissions report for the MRR, it is not clear relative to projects since most have a single primary source of GHG emissions. We request the removal of this clause or if it is still considered important, we request additional clarification in the Regulations regarding the performance of this ranking in the context of emission reduction projects. (FIRSTENVIRON3)

> **Response:** The term "GHG emission source" is defined in section 95802 of the regulation.

M-57. Comment: We request that the language in section 95977.1(b)(3)(A) be changed to indicate that "The Offset Project Operator or Authorized Project Designee must provide to the verification team the following information necessary to develop an Offset Verification Plan" instead of specifying that the verification team must obtain this information since the list that follows is clearly information that the Offset Project Operator or Authorized Project Designee would possess and could provide. (FIRSTENVIRON3)

Response: We agree and modified the regulation accordingly.

M-58. Comment: The requirements for offset verification services in section 95977.1 roughly correspond to the verification approach contained in ISO14064 Part 3 (the standard) which represents recognized international best practice regarding the performance GHG verification. However, the Regulation's requirements omit several steps specified by the standard. These omissions include, but are not limited to, an initial strategic review, and more significantly, the assessment of the GHG information system and its controls, an assessment which originates from financial auditing, from which GHG verification best practices were derived. In addition, the Regulation lacks the detailed guidance regarding the performance of verification activities contained in Annex A of the standard. For these reasons, we believe that the verification process as presented in the Cap and Trade Regulation does not meet the standard of international best practice. Recognizing that activities implemented under AB 32 provide an example to other North American programs and beyond, we strongly encourage ARB to ensure the regulations are consistent with international best practice by either incorporating all of the requirements of ISO 14064 Part 3 into the Regulation, or incorporating its requirements by reference to the standard. (FIRSTENVIRON3)

Response: We believe that the offset verification requirements do embody the best practices provided in the ISO 14064 guidance. We do not believe a change is necessary

M-59. Comment: Modify section 95977 as follows:

(g) The Board shall periodically review and evaluate the relationships between verifiers and verification bodies and project developers and consider a system where the Board assigns verifiers or verification bodies for each project. (UCS7)

Response: We did not make this change. The regulation contains rigorous conflict-of-interest provisions to guard against inappropriate relationships between verifiers, verification bodies, and project developers. This additional requirement is unnecessary, as its intent is to provide the same result.

M-60. Comment: We recommend against the revised definition of "Offset Material Misstatement" that would allow the first five percent of emissions over the reported level to be protected from enforcement. By including this language, ARB has essentially raised the cap by five percent. It is not necessary from a programmatic standpoint, and is not allowed in other air programs. If ARB continues to allow this exclusion, at a minimum, the rule should be clear that if an entity under-reports by more than the five percent “free” level, all under reported emissions will be subject to violation, not just emissions beyond five percent. (CAPCOA2)

> **Response:** We disagree that the material misstatement “essentially raised the cap by five percent.” Offset projects are calculated using conservative methods that take into account uncertainty. Due to the conservative methods, the five percent level does not artificially raise the cap. Because the comment falls outside the scope of the notice, no further response is required.

M-61. Comment: In order to protect against gaming and conflicts of interest, there should be a periodic review the relationships between verifiers and project developers. CARB should consider a system where the CARB executive officer assigns a verification body, or a list of three verification bodies from which to choose, to each offset project. (UCS6)

> **Response:** We are committed to continually evaluating the verification bodies' services as specified in the ARB's regulatory requirements and the verification bodies' professional care and conduct to ensure the integrity and consistency of verifications. As part of this oversight process, each reporting year, ARB staff will audit every active verification body to ensure verifiers are providing high quality offset verification services. Audit findings and observations are sent to verification bodies at the completion of verification services in order for each verification body to take any necessary actions to improve their performance. We will not take on the additional workload to assign verifiers and then try to negotiate fees between project developers and assigned verifiers.

M-62. Comment: Section 95977.1(b)(3)(D)(2)(h) prohibits a project from receiving CARB offset credits or registry offset credits if it does not meet the requirements of section 95977.1(b)(3)(D)(2)(f) regarding compliance with local, state, and federal environmental laws. This prohibition should apply to a project that does not meet any requirement of the Cap and Trade rule. (SCAQMD4)

> **Response:** We believe the regulation does require offset projects to meet the requirements of the cap-and-trade program to be issued offset credits.

General Verification Process

M-63. Comment: The annual reporting and six year site visits as well as full inventory every 12 years should only be required for the crediting period. ARB should develop monitoring period requirements that recognize the 100 year permanence and the need being of lower resolution, and an investment and detail level that demonstrates that the level of onsite carbon stocks must be maintained at or above that amount needed to assure all registered tonnes. For example a satellite monitoring of change detection could be more than reasonable for monitoring period needs and cost effective. (CFA2)

Response: We will continue to discuss these types of alternatives for post-project monitoring with stakeholders. We need to review and evaluate any alternatives before making a change to the regulation as part of a separate rulemaking.

M-64. Comment: While we agree the list included in section 95977.1(b)(3)(L)(3) includes data checks that could be performed for a particular source, not all of them would be necessary, appropriate, or efficient to confirm the accuracy of source data so we would request that "at a minimum a data change must include the following" be changed to "at a minimum a data check may include one of the following." (FIRSTENVIRON3)

Response: We modified section 95977.1(b)(3)(L) to require a verification team to clearly show how the riskiest sources of offset project information were reviewed for accuracy. This is needed to provide written documentation that the verification team fulfilled its regulatory verification requirements, and to provide a minimum standard for all offset verifications.

M-65. (multiple comments)
Comment: The requirement in section 95977.1(b)(3)(R)(4)(c) for verifiers to have "a final discussion with the Offset Project Developer" is in our opinion and experience unnecessary. We strongly suggest that there needs to be more flexibility. (CIG2)

Comment: Further, the requirement in section 95977.1(b)(3)(R)(4.)(d.) for verifiers to have "a final discussion with the Offset Project Developer" is also, based on our experience, unnecessary. We strongly suggest that this requirement be eliminated. In addition, section 95977.1(b)(3)(D) requires verifiers to make a site visit every year. We suggest that the requirement could be made more flexible, while still achieving the same purpose, if verifiers were required to undertake a site visit within two months of the end of the reporting period. (CERP4)

Response: In our experience with inventory verification under the MRR, too often the verifiers failed to communicate their findings to their clients before submitting a verification statement to ARB. It is important for offset project developers to understand the findings from verification services from their verifiers.

We changed the regulation to require that a site visit for non-sequestration projects must be conducted in the year that offset verification services occurs. For smaller projects that opt to conduct verification every two years, a site visit will only be required in the second year (the year in which full offset verification services are provided).

M-66. (multiple comments)
Comment: Finally, we strongly urge ARB to recognize that small-scale projects cannot and should not have to carry the full verification burdens borne by larger projects. In

particular, we recommend that ARB allow projects below a certain ton threshold to undertake a site-visit verification every two years instead of annually (the project still could report annually). CERP recommends a threshold of 25,000 metric tons CO_2e/yr for this threshold. This is the same threshold ARB uses for reporting of emissions by sources. A lower threshold (such as 10,000 tons) would be too small; many Offset Project Operators would have to do a significant amount of work even to determine whether they meet such a lower threshold. By contrast, 25,000 tons/yr is an appropriate, established, and credible threshold for what constitutes a small-scale project that should merit a once-every-two years site visit rule. (CERP4)

Comment: The existing CAR protocols and the draft Compliance Offset Protocols take a performance-based approach for determining the eligibility of projects to generate offsets. We agree with this. We believe that it provides project developers, such as Camco, with greater certainty that projects will be able to register offsets and reduce overall transaction costs. This will be particularly beneficial to smaller-scale projects. We believe that ARB must uphold the environmental integrity of the Cap and Trade program. However, the way to address integrity for small-scale projects is to make the protocols conservative, by default, to minimize the chances of over-estimating emission reductions. Further, we believe that Regulations should be scalable to reflect the contribution and impact smaller-scale projects can have on the overall system. ARB should recognize that all offset projects do not have the potential to pose the same threat to the level of environmental integrity intended by the law and regulation, and that the Regulations should take account of the scale of the offset action. While the principle of environmental integrity must be maintained in all eligible offset projects, the various costs of ensuring that integrity, from administrative, management to MRV costs, should reflect the scale of the project, particularly for small-scale projects. It is important to allow smaller-scale projects flexibility to demonstrate their emissions reductions, if we are to encourage the development of these types of small-scale activities. The CDM (and other standards) allow greater flexibility for smaller-scale projects. There are simplified project design and MRV procedures for these size projects which significantly reduce the costs of registration, monitoring, reporting and verification. We strongly suggest that the same principles for small-scale offset projects be applied in California, following international best practice. (CIG2)

Comment: Small and mid-scale agricultural producers because of the size or nature of their operation may find that, they alone do not qualify for a sufficient number of offset credits to make the project application and verification process worthwhile. To avoid disadvantaging small and mid-scale producers in the marketplace, where they must compete on price for their commodities with larger competitors who may benefit financially from the carbon market and, therefore, could offer their commodities for lower prices than their smaller competitors, CARB or the state of California (through California Department of Food and Agriculture or the Department of Conservation) should consider other ways to support innovative, conservation-oriented small and mid-scale producers who provide climate change mitigation benefits in California. We describe in greater detail below how allowance revenue can be used to support these efforts. (CACAN3)

Response: We included provisions to allow for projects below 25,000 tons/yr to opt to conduct verification every two years. We changed the regulation to require that a site visit for non-sequestration projects must be conducted in the year that offset verification services occurs. For smaller projects that opt to conduct verification every two years, a site visit will only be required in the second year (the year in which full offset verification services are provided).

M-67. (multiple comments)
Comment: We do not believe the requirement under section 95977.1 (b)(3)(R)(1) for verification reports to be scrutinized by a different independent person each time is necessary, practical or workable. We believe that after two or three projects, verifiers will no longer have the staff to "independently" review projects, if this requirement for different, independent parties is applied to each verification report. (CIG2)

Comment: CERP strongly believes that a sound system of independent project verification is the bedrock for environmental integrity in the offsets program. However, we have grown concerned that the verification-related regulations have become overly and unnecessarily restrictive. The regulations now go beyond what is needed to safeguard environmental integrity, reaching a point where the burdens and costs will dissuade the development of even the highest-quality projects. Already, the Climate Action Reserve process takes an average of three months to navigate; the additional layers imposed by the ARB regulations will mean that many projects will be approaching the nine month "hard" deadline for data reports. In other words, it is an example where the perfect is the enemy of the good. For example, section 95977.1(b)(3)(R)(1.) requires that verification reports be scrutinized by a different independent person each time. In our view, this requirement is not practical, workable—or necessary. It is very possible that, after two or three projects, a verifier will no longer have the staff to verify projects if this requirement for different, independent parties is applied. (CERP4)

Response: We did not make this change. The commenter's suggestion is contrary to the basic premise that an offset project be subject to an internal independent review to ensure that the verification process and findings are appropriate for the offset project.

M-68. (multiple comments)
Comment: Page A-184 (c) and (d) Annual Verification Required. While (c) grants sequestration projects the ability to verify every six years, (d) states that credits which are not verified within 9 months of the end of each (yearly) Reporting Period cannot ever be registered, and are thereby lost. Such an annual verification requirement would impose an unnecessary burden on smaller projects that do not generate sufficient carbon volume to justify annual verification expenses. We recommend these sections be clarified to require verification within 9 months of end of the last Reporting Period being verified, with the ability to include multiple reporting Periods in one verification report. (BLUESOURCE2)

Comment: Section 95977(d) conflicts with section 95977(c). Section 95977(c) allows sequestration projects to verify annual Offset Project Data Reports at up to 6 year intervals. Section 95977(d) requires that a verification statement be submitted within 9 months after the conclusion of each Reporting Period. We recommend that this section is amended to allow for the provision for sequestration projects. (FINITE)

> **Response:** We agree and modified section 95977(d) to the following: "Any Offset Verification Statement must be received by ARB or an Offset Project Registry within nine months after the conclusion of the Reporting Period for which offset verification services were performed."

M-69. Comment: We are concerned by the prescriptive nature of the actions a verifier is required to undertake, as set out in section 95975. A verifier will have to be accredited by ARB and will have to follow the requirements of a protocol. Adding additional requirements will raise transaction costs in four ways. First, it will require verifiers to do more work they are already doing, thus leading to unneeded duplication. Second, it increases the verification timeline for the project. Third, it increases the risk that there is overlap and confusion between the Regulations, the Protocols and ARB's accreditation process. Finally, it may raise the cost of liability insurance. Currently, verification requirements are the same regardless of the size of project. Incorporating requirements into protocols would allow ARB to provide for more flexibility depending on the size of each project. Currently, under CAR it takes some three months for projects to complete the verification process. Adding additional steps will increase the time period for verification. It has the potential of making the process longer than 9 months, thereby contravening section 95976(d)(6) and 95977(d). (CIG2)

> **Response:** We disagree that the verification requirements in the regulation are too prescriptive. We included requirements for a verification program that are consistent with international standards and subject to ARB oversight. This oversight includes verifier accreditation, verification body accreditation, requirements for verification services, and conflict-of-interest requirements. The regulation includes enforcement provisions that apply to parties that participate in the offset program. These parties include offset project developers, verifiers, and covered entities. To establish a high level of trust in the program and address public concerns related to the integrity of offset projects, staff has developed a verifier accreditation process and conflict-of-interest process that ensures quality in the evaluations and prevents potential bias when offset projects are verified by independent third parties. These requirements are necessary to ensure the integrity of the overall program and that claimed GHG reductions and GHG removal enhancements have been achieved in accordance with the regulation and Compliance Offset Protocols.
>
> We believe that nine months is sufficient time to complete the verification process. We modified the timing for verification so that there is not an annual fixed "verification period," and that the new requirements cover a reporting period that is not tied to the calendar year.

Site Visits

M-70. Comment: The list of activities identified in section 95977.1(b)(3)(D)(1) required for site visits includes items that, because of aspects of the actual assessment performed, may be performed more accurately or efficiently during a desktop review not during the actual site visit. While the activities in section 95977.1(b)(3)(D)(1)(c) and (e) represent reasonable and appropriate site visit activities, we assert that the activities in sections 95977.1(b)(3)(D)(1)(a), (b), (d), and (f) are not either appropriate for a site visit or more accurately and efficiently performed during off-site desktop review and, therefore, should be removed from this clause of the regulation. The list of activities in section 95977.1(b)(3)(D)(2) required for site visits includes items that, because of aspects of the actual assessment performed, may be performed more accurately or efficiently during a desktop review, not during the actual site visit. While we agree that the activities in section 95977.1(b)(3)(D)(2)(a), (c), and (d) represent reasonable and appropriate site visit activities, we assert that the activities in section 95977.1(b)(3)(D)(2)(b), (f), (g), and (h) are not either appropriate for a site visit or more accurately and efficiently performed during off-site desktop review and, therefore, should be removed from this clause of the regulation. (FIRSTENVIRON3)

> **Response:** We modified section 95977.1(b)(3)(D)(2.)(i.) in response to stakeholder comments to allow flexibility to the verification team to conduct some verification services offsite, and not during the time spent at the offset project site. Specifically, the activities performed pursuant to sections 95977.1(b)(3)(D)(2.)(f.) through (b)(3)(D)(2.)(h.) may be included in a site visit or, alternatively, may be conducted as part of a desk review.

M-71. Comment: Section 95977.1(b)(3)(D) requires verifiers to make a site visit every year. We suggest that it would be much more flexible if they were required to undertake a site visit within two months of the end of the reporting period, allowing the project developer flexibility as to when to schedule a site-visit while still requiring a site visit occur in order for offsets to be issued. (CIG2)

> **Response:** We changed the regulation to require that a site visit for non-sequestration projects must be conducted in the year that offset verification services occurs. For smaller projects that opt to conduct verification every two years, a site visit will only be required in the second year (the year in which full offset verification services are provided).

Offset Verifier Accreditation

M-72. Comment: Regarding section 95987(e), we note that most major U.S. carbon registries which could be expected to serve as registries under ARB's Cap and Trade program and perform this audit function have previously signed MOUs with the American National Standard Institute to accredit verification bodies and audit the verification body verification activities. We believe that this demonstrates the registries' acknowledgement of ANSI's competence and value in performing this activity. We encourage ARB to likewise consider ISO 14065 as the standard of accreditation for verification bodies under the Cap and Trade Regulation and assign responsibility to accredit and audit offset project verification bodies to the American National Standards Institute. (FIRSTENVIRON3)

Response: The ARB accreditation program was developed using international best practices as laid out in ISO 14065, which is the standard to which greenhouse gas verifiers need to be accredited. The ISO standards are meant to be guidelines that programs can use to develop and tailor for their own program needs. The standard is program neutral.

ARB's verification accreditation program is consistent with the ISO 14065 standard for accrediting verification bodies. The following list highlights the areas in ARB's verification body requirements that are inclusive of all of the major requirements in the ISO 14065 standard:

- Be a legal entity that can be held accountable;
- Possess an internal conflict of interest policy, mechanisms to monitor, and requirements to remove and control for conflicts if they arise;
- Maintain Liability Insurance;
- Competencies for sectors, if applicable;
- Requirements to form verification teams with appropriate skills for verification of special sectors;
- Take responsibility for any subcontractors potential for conflict of interest with the client and the quality of their work;
- Identify a verification team lead; and
- Maintain record retention requirements.

However, we chose to advance the requirements for accreditation past the ISO 14065 standard for verification bodies to the level of individual verifiers. This higher standard of verifier accreditation has only recently been considered by ISO as they sought to develop a new ISO 14066 standard that seeks to attain California's higher level of competency for verifiers. We chose to add such a

requirement to ensure a competency standard at a level beyond that currently required by international best practices. This includes a minimum educational and work experience requirement for individual verifiers. It also includes training and accrediting verifiers as sector specialists. We have developed a training program that builds on international GHG auditing skills and ARB's regulatory requirements for reporting and verification. In the future, ARB's training program will be updated to include general offset verification and offset project-specific verification training for verifiers interested in providing verification services for offset projects to support the proposed Cap-and-Trade offsets program.
We are committed to continually evaluating the verification bodies' services as specified in the ARB's regulatory requirements and the verification bodies' professional care and conduct to ensure the integrity and consistency of verifications. As part of this oversight process, each reporting year, ARB staff will audit every active verification body to ensure verifiers are providing high quality offset verification services. Audit findings and observations are sent to verification bodies at the completion of verification services in order for each verification body to take any necessary actions to improve their performance.

M-73. Comment: We recommend that CARB institute a regular and detailed performance review of verification bodies. The results of performance reviews should of course be factored into the re-accreditation process. (UCS6)

> **Response:** We agree and included language requiring offset verifiers and Offset Project Registries to undergo performance reviews.

M-74. Comment: An important factor in ensuring a sufficient supply of early action credits for use in compliance will be the availability of verifiers. Evolution Markets experience in other offset markets, such as the Clean Development Mechanism (CDM) under the Kyoto Protocol, has shown that an insufficient number of verifiers can present significant delays in the development of projects and the issuance of credits. A lack of verifiers not only has the ability to restrict supply but introduces an element of uncertainty in the timing of credit supply that has corresponding price risk for compliance buyers of offsets. Therefore, Evolution Markets recommends ARB make the creation of the accreditation program for verifiers a priority upon the completion of this set of rule changes. Efforts to establish the accreditation program and initiate the accreditation process will allow holders of CRTs to begin the process of conversion to ARB offset credits in advance of the onset of compliance obligations, ensuring a robust early supply of offsets to be used as a cost containment mechanism. (EVMKTS2)

> **Response:** We are in the process of developing the training for offset verifiers and plan to accredit offset verifiers in 2012.

M-75 Comment: At the time of verification of the first forest carbon offset projects, the Climate Action Reserve Forest Project Protocols were not accredited under the American National Standards Institute. (SCS2)

Response: We acknowledge the comment, but no change is necessary.

M-76 Comment: Since the FPP, Version 2.1 was not an ANSI-accredited standard and no Project Design Document (PDD) was required, the limited extent of project documentation and transparency for the Offset Project Data Assessment will likely present many challenges in conducting an ex post facto materiality test, as presently proposed by ARB. Many of the discussions related to computations and spreadsheets were conducted in person and were not well-documented. Also, the cases where the original project developers are no longer involved in the project (e.g., John Nickerson for the van Eck Forest Project) may present challenges. (SCS2)

Response: We understand that early action credits that go back several years may have challenges in documentation. However, as these offset credits may be used in a regulatory program, there needs to be a rigorous verification process to ensure that the early action offsets meet the AB 32 criteria as defined in the regulation to be used for subsequent compliance. We did not make any changes that set a different standard for credits issued under early action programs to ensure that we maintain the environmental integrity of the ARB cap-and-trade program.

Offset Verifier Conflict of Interest

M-77. Comment: At present, offsets developers directly hire verifiers to verify the reductions they claim to have made. There is an inherent conflict of interest in the relationship between the developer and the verifier. Under this arrangement, verifiers have incentives to charge less, do less, and be less strict in their assessments in order to be hired again by the same developer or other developers. Given this inherent conflict of interest, effective government oversight of the quality of verification services is essential. An important change that needs to be made to the draft regulation is to institute a performance review of verification bodies. The results of performance reviews should be factored into the reaccreditation process. CARB should periodically review the relationships between verifiers and project developers and consider a system where the Board assigns verification bodies to each offset project. CARB must ensure that the registries participating in ARB offset generation have the expertise needed to perform their role overseeing verifiers and offset report quality and that they are performing their oversight tasks adequately. CARB must review the performance of the registries in conducting their oversight tasks and use discretion in approving registries. CARB should also consider the following:

- Offset Project Data Reports should be made publically available along with the verification reports.
- Offsets projects should be required to not cause significant adverse effects on human health or the environment.
- It is a positive improvement that developers must disclose if their projects are generating credits under another voluntary or mandatory greenhouse gas program. To ensure that developer statements are correct and that credits are

not double counted, CARB must also actively reach out to other voluntary and mandatory crediting programs to seek instances of double counting. (UCS7)

Response: We believe our conflict-of-interest rules for offset verifiers are very strict and meet a high standard of rigor. We included language requiring offset verifiers and Offset Project Registries to undergo performance reviews. In addition, the regulation proposes a robust monitoring program for offset projects—both the verification that the offsets are real, additional, and enforceable, and that Offset Project Operators, verifiers, and Offset Project Registries are operating according to regulatory requirements. Offset Project Registries are required to conduct oversight of their registry program and randomly audit verifications to ensure that our regulatory requirements are being met by Offset Project Operators and verification bodies. We will provide rigorous oversight of our approved Offset Project Registries. In addition, we designed our regulatory offset verification program to provide a transparent process by which we can review verification documents and fully understand any findings uncovered during the course of verification of an offset project by an ARB-accredited verification body. We will also develop an audit and oversight program for offset project verifications. All oversight functions are part of implementation and need not be specified in the regulation.

We did not require that registries make Offset Project Data Reports publicly available as we already include requirements for key parts of the offset project data reports to be made publically available.

The Compliance Offset Protocols approved in the cap-and-trade regulation must undergo a CEQA review and are designed to avoid significant adverse effects on human health or the environment. Some projects may be required to do an additional project-specific CEQA analysis prior to implementation if required by local regulations.

M-78. Comment: We request clarification on section 95979(b)(3) regarding what constitutes an “incentive” as defined under this clause. (FIRSTENVIRON3)

Response: The term “incentive” is used in the context of conflict of interest, where a gift or work in-kind may compromise the objective review of an Offset Project Data Report.

M-79. Comment: After substantial contemplation of this issue by the OWG, the OWG expresses its concern surrounding the true opportunity for conflict of interest issues to arise by including an Air Quality Management District (AQMD) as an offset verifier. Since the AQMD’s are essentially governed by ARB, it is impossible to assume that their role could be completely separated from ARB’s role as the primary regulator of the entire cap-and-trade program. In addition, many of the Covered entities, including all members of the OWG, hold title to air permits issued and overseen by their regional AQMD’s. There is no certainty in the regulations to prevent an AQMD from holding such an air quality permit to an additional standard above the current state requirements by requiring the Covered entity to purchase additional offsets beyond what is allowed under the cap-and-trade program. Further, the role of offset verification is out of the scope of the AQMD's regulatory authority. Exercising this role seems to create a conflict through unauthorized use of taxpayer funds. (OFFSETSWG3)

> **Response:** We do not govern air districts. The air districts are not required to provide offset verification services; any decision to do so would be a voluntary decision on the part of the district. Furthermore, it is optional for covered entities to use air districts as offset project verifiers if there are any concerns about service or conflicts of interest with their regulatory duties.

Issuance of ARB Offset Credits and Registry Offset Credits

General Issuance Comments

M-80. Comment: Subarticle 13: ARB OFFSET CREDITS AND REGISTRY OFFSET CREDITS. The Utilities are members of the Offsets Working Group (OWG) and refer to comments submitted by the OWG on items within this Subarticle. (MID3)

> **Response:** Thank you for your comments. We have reviewed and responded to the OWG comments.

Timing for Issuance

M-81. (multiple comments)
Comment: The ARB process has a timeline for offset credit issuance that defines the timelines for ARB's intermediate steps and the resultant credit issuance. The starting point, however, is not fixed in time. The regulations should set the timeline for ARB to begin its review of Verification Statements submitted for approval. This will create more certainty for OPOs and serve as a guideline for their data submissions to ARB. In addition, a maximum timeline will benefit Covered entities that are considering the purchase of offset credits near the end of a compliance period. The OWG supports an addition to Section 95981.1 as follows:

Section 95981.1. <u>Process for Issuance of ARB Offset Credits</u>

(a) <u>ARB will review the Positive Offset or Qualified Positive Offset Verification Statement within 30 calendar days after submission to ARB by an Offset Project Registry, Offset Project Operator, Authorized Project Designee, or any other third party authorized by the Offset Project Operator</u>. (OFFSETSWG3)

Comment: PG&E welcomes the added language in section 95981.1 on the process for issuing offset credits. The one recommendation PG&E would make to this section is the addition of a deadline for ARB to determine the completeness of a submission by a project operator. PG&E would like to suggest that a deadline of 30 days be added to the Regulation. PG&E is supportive of the other deadline additions, including that ARB will issue credits to offset project operators 30 days after it determines completeness, that ARB will then notify the project operator 15 days later, and ARB will place credits in the account 15 days later. Modify section 95981.1 as follows:

> <u>(a) ARB will review the Positive Offset or Qualified Positive Offset Verification Statement within 30 calendar days after submission to ARB by an Offset Project Registry, Offset Project Operator, Authorized Project Designee, or any other third party authorized by the Offset Project Operator.</u> (PGE4)

Comment: There are no timelines set under the issuance of ARB offsets for the review of offset verification statements. If ARB requires the project developer to operate within tight time schedules, then it needs to provide similar timescales for itself and for standards bodies. This would provide greater certainty for owners and buyers on delivery schedules for credits and would better standardize the overall verification process, thereby reducing costs and increasing transparency. (CIG2)

Comment: There is no deadline for ARB to make the threshold completeness determination; the absence of such a deadline will add uncertainty and costs to the process. The absence of a deadline also deprives interested parties of any recourse in the event that ARB is dilatory. Accordingly, CERP respectfully requests that ARB have no more than 30 days to make such a determination. (CERP4)

> **Response:** We made changes to the timing for issuance of offset credits. We will review the Offset Verification Statement within 45 calendar days of receiving it (new section 95981(c)) and issue ARB offset credits within 15 days of making the determination that the Offset Verification Statement is positive or a qualified positive (section 95981.1(a)). Within 15 days, ARB will transfer the ARB offset credits into the appropriate Holding Accounts (section 95981.1(f) and notify the recipients (section 95981.1(c)). We believe the notification and transfer of ARB offset credits into the appropriate Holding Accounts can be done simultaneously and do not have to occur consecutively.

M-82. Comment: Section 95981.1(d)(4) appears to say that the Executive Officer's decision to deny issuance of CARB offset credits is "final." This should be clarified to state "subject to judicial review." (SCAQMD4)

> **Response:** ARB is the final arbiter of determining whether or not ARB offset credits should be issued. Therefore, we did not make this change.

M-83. Comment: Under section 95981(c)(1) the project developer is asked to state that reductions “will be measured.” This is hard to attest to, as developers may not have the rights to a project for its entire crediting period. We believe this might be an error in the text, as it is inconsistent with the spirit of the rest of the text. For a particular verification period the developer can only attest that the reductions “have been measured.” (CIG2)

Response: We agree and made this change.

Authorized Project Designee

M-84. (multiple comments)
Comment: The buyer liability approach in the draft rules does not efficiently address the problem of invalidated credits. Under ARB's proposed rules, the holder or user of a credit is presumptively liable. If that party is no longer in business, ARB will require the Offset Project Operator or Authorized Project Designee to replace the invalidated ARB credits. The Trust recommends that the Authorized Project Designee be removed from this requirement. The Authorized Project Designee is defined in section 95802(a)(21) as "an entity authorized by an Offset Project Operator to act on behalf of the Offset Project Operator". There are many situations where the Authorized Project Designee has no connection with the actions that lead to invalidation. One obvious example is where the discrepancy is due to intentional acts of the verifier, or project registry. (TCT)

Comment: While the definition of "authorized project designee' is straightforward, the liabilities associated with this designation are significant since they can ultimately be held liable for replacing offsets affected by an intentional reversal or invalidation. It is advantageous to project owners to designate a third-party to take on the task of project development. These third-parties are often consultants and other small businesses. While the ability to assign an APD has utility to project owners, the liabilities associated with it will prevent consultants from taking on this role. We recommend that liabilities for reversals and invalidation exclude the Authorized Project Designee under this Regulation. (FINITE)

Comment: The Regulation assigns significant liabilities to the "Authorized Project Designees," who do not have control over forest management or project standing, and may lack the financial upside or resources to bear such liabilities. We recommend that default liabilities for reversals and invalidation therefore exclude the Authorized Project Designee. This would not preclude the Offset Project Operator from assigning these liabilities to Designees who have the financial resources to bear them via contracts or reduce ARB's ability to regulate the project itself. (BLUESOURCE2)

Response: We agree and removed the Authorized Project Designee from being responsible for replacing invalidated ARB offset credits.

Crediting Periods for Compliance Offset Projects

M-85. Comment: CERP is concerned about what will occur if a project resubmitting its information to a new registry misses a deadline for a reporting its reductions. The regulations suggest that in this case the crediting year may simply be lost. CERP recommends modifying section 95986(k)(3) so that it is clear that a project may have an extension of relevant crediting deadlines if the re-submission process is time consuming. Modify section 95986(k)(3) as follows:

An Offset Project Operator or Authorized Project Designee who has been notified by an Offset Project Registry of a suspended or revoked approval must re-submit its project information with a new Offset Project Registry or ARB. An offset project listed at ARB or a new Offset Project Registry will continue to operate under its originally approved crediting period, provided that ARB may extend the crediting period or the relevant deadline in section 95977(d) for one year if ARB determines that such extension is necessary to provide time for re-submission of information to the new Offset Project Registry or ARB. (CERP4)

Response: Original section 95986(j), now section 95986(l), was modified to clarify what happens to offset projects that reside at an Offset Project Registry, whose approval has been suspended or revoked. These offset projects may transfer to another approved registry and continue its current crediting period. This change was necessary because stakeholders were concerned that their offset projects could be ineligible if an Offset Project Registry's approval was suspended or revoked.

In addition, new section (l)(3) allows offset projects that must transfer to another registry in the event their current registry's approval is revoked to qualify for a one-year crediting period extension. These modifications were made in response to stakeholder comments that switching Offset Project Registries could cause a delay in the reporting of GHG reductions and GHG removal enhancements and subsequently cause those reductions to be ineligible for crediting.

M-86. (multiple comments)
Comment: Section 95972(b) limits the crediting period for sequestration offset projects to no greater than 30 years. WSPA believes that 30 years is too short for a crediting period for geologic sequestration projects. WSPA recommends that the Regulation be amended to provide 100 year crediting period for geologic sequestration projects. (WSPA3)

Comment: The OWG repeats its request for extending the crediting period for forestry projects. Firstly, forestry projects are required to exist for at least 100 years and a 10-30 year crediting period establishes an arbitrary limitation. Secondly, a typical reforestation project will produce the majority of its emission reductions in the second half of its 100-year project term. Forest project operators should be given greater certainty than provided by a 10-30 year crediting period. They are already required to file annual reports to ARB and be verified no later than every 6 years. With these limitations, it's not as if a reforestation project could operate "under the radar" if the crediting period were extended to 50 years. The OWG refers ARB back to the data on the Cuyamaca Rancho State Park reforestation project that was entered into ARB's official record by the OWG's comments on the 45-Day language. The OWG believes that the data provides substantial evidence for increasing the crediting period to 50 years. (OFFSETSWG3)

Response: We do not agree that the crediting period for forest carbon projects should be extended. The intent of a 25-year crediting period is not to limit sequestration of carbon and offset issuance from forest projects. In fact, renewal periods allow for forest projects to sequester carbon and obtain offset credits beyond the 25-year crediting period. A crediting period of 25 years allows for the updating of protocols, if necessary, ensuring that projects use the more up-to-date factors (e.g., leakage, buffer account) and scientific standards.

Invalidation and Forest Reversals

Invalidation Provisions

M-87. Comment: CCEEB recommends the obligation to replace offset tons due to reversals should be treated differently depending on the cause of the reversal. For intentional or fraud-related reversals, such as when a forest offset developer decides to harvest the forest, then the developer who is making the business decision should be responsible for replacing the lost carbon sequestration. For unintentional reversals due to causes such as forest loss from fire, pests, disease, or bankruptcy, the lost carbon should be replaced from a reserve held back when credits are issued for such projects. CCEEB recommends that ARB provide for the establishment of such a reserve by itself or by another agency. (CCEEB3)

Response: Section 95983(b)(2) now states that we will retire a quantity of ARB offset credits from the Forest Buffer Account in the event of an unintentional reversal. Sections 95983(c) and (d) specify that in the event of an intentional reversal, the Forest Owner must replace ARB offset credits to ARB in the amount specified in the regulation. In addition, the definition of a "Forest Owner" is such that there can be multiple Forest Owners. We have enforcement authority over all Forest Owners involved in the offset project, and the Forest Owners can determine through contractual arrangements how to handle replacement obligations among themselves.

M-88. (multiple comments)
Comment: CARB's ability to decertify an offset after it has been purchased and impose liability for this decertification on the offset purchaser, will have the direct effect of pulling allowances out of the market as a hedge against decertified offsets, raising allowance prices and compliance costs for all capped entities. Given the stringency of offset approval, it is questionable why CARB would even propose to decertify offsets that had already qualified under the most rigorous rules. (AB32IG2)

Comment: For the foregoing reasons, covered entities and other buyers will avoid offsets issued by ARB if they carry with them the risk of later invalidation. This avoidance could have significant implications in the event that California ultimately links its program with other Western Climate Initiative (WCI) jurisdictions. If one or more of the other WCI jurisdictions adopts a different approach to addressing post-issuance offset discrepancies, then covered entities throughout the WCI will gravitate to offsets issued by those other jurisdictions. This will distort the efficiency and effectiveness of a broader WCI market. It also will mean that buyers will steer way from projects based in California. (CERP4)

Comment: BP supports the comments submitted by IETA and others which clearly articulate the perils of a "Buyer Liability" system. Such a system is likely to stunt the formation of a robust market for offsets as it will reduce the ability of market participants to consider offsets as fungible compliance instruments. (BP2)

Comment: In its role as a seated Director to both the International Emissions Trading Association (IETA) and Environmental Markets Association (EMA), Barclays endorses the comments regarding buyer liability filed by IETA and EMA, on August 11, 2011. (BARCLAYS)

Comment: The buyer offset liability language in section 95985 is problematic because buyers suffer sanctions or must replace credits that, though approved by CARB, later turn out to be invalid. The net effect will be higher offset transaction costs than need be; programmatic compliance costs will be higher; existing, standard seller liability used in all other cap and trade programs in the US and EU will be duplicated; offsets we be judged by the market to be second class compliance instruments; faced with higher costs, sources on the margin will expand their operations and/or export jobs outside the jurisdiction of AB 32. (CIPA)

Comment: SCPPA has strong concerns about ARB's "buyer liability" approach to addressing situations in which problems are identified with offset credits after they have been issued in section 95985. To be clear, SCPPA believes the risk of such post-issuance problems is small because of the rigor of the ARB's offset regulations. However, any policy under which already issued offset credits carry a risk of invalidation will prevent the development of a market in offsets and the current provisions make it very easy for invalidation to occur. An unworkable offsets program would have very adverse consequences for the AB 32 program, as shown by ARB's own March 24, 2010, economic analysis. As part of this analysis, ARB modeled the cap and trade program under a scenario in which no offsets could be utilized. Relative to the baseline case (in which offsets are utilized to the full 8 percent limit), ARB's modeling concluded that this "no offsets" scenario would yield allowance prices in 2020 that would be $108 higher ($148/ton instead of $30/ton)—resulting in $18 billion more in costs in that year alone [*Id.*, at p. ES-7 (Table ES-2)]. The current buyer liability approach effectively will drive the AB 32 program to the "no offsets" scenario. (SCPPA6)

Comment: ARB's ability to invalidate offsets would place liability on those entities holding or using offset credits to meet their compliance obligation. IETA warns buyer liability is not a workable approach to addressing post-issuance problems with offsets for the following reasons:

1. A buyer liability rule will prevent the development of a viable offsets program, resulting in adverse impacts on the entire A.B. 32 effort**.** IETA has strong concerns about ARB's "buyer liability" approach to addressing situations in which problems are identified with offset credits after they have been issued (see section 95985). To be clear, we believe the risk of such post-issuance problems is small because of the rigor of the ARB offset Regulations. However, any policy under which already-issued offset credits carry a risk of invalidation will prevent the development of a market in offsets—and the current provisions make the circumstances very easy for invalidation to occur, as they are very open-ended and non-specific thus giving a "free hand" to the regulator to decide when, where and how to invalidate offsets. An unworkable offsets program would have very adverse consequences for the AB 32 program, as shown by ARB's own March 24, 2010 economic analysis. As part of this analysis, ARB modeled the Regulations under a scenario in which no offsets could be utilized. Relative to the baseline case (in which offsets are utilized to the full 8 percent limit), ARB's modeling concluded that this "no offsets" scenario would yield allowance prices in 2020 that would be $108 higher ($148/ton instead of $30/ton)—resulting in $18 billion more in costs to compliance entities and subsequently Californian consumers in that year alone. The current buyer liability approach effectively will drive the AB 32 program to the "no offsets" scenario.
2. Buyer liability is neither fair nor efficient. In the case of offset discrepancies, it almost certainly will be the offset project operator, verifier, or offset project registry that is at fault—and, under the Cap and Trade Regulations, each of these parties submits to the jurisdiction of ARB. Yet, under ARB's proposed buyer liability rules, the holder or user of a credit is presumptively liable. This arrangement turns fairness on its head. In addition, the approach is highly inefficient. To be efficient, a liability system should impose liability on the party that has the most information and ability to control performance as well as minimize the number of legal actions that must be filed to garner a resolution. Most covered entities do not have any special insight into methane digesters, ozone-depleting substances, or forestry. In an offsets program, covered entities will rely on the work of verifiers—and on ARB itself as credit issuer. For this reason, making covered entity buyers liable for problems not detected through the regulatory system will impose substantial new costs on buyers without materially reducing the risk that such problems will occur. ARB officials also have asserted that buyers can easily and efficiently manage their liability risk through contracts. This view is not consistent with marketplace realities. A viable offsets program will involve the participation of many buyers and sellers—including aggregators who intermediate between smaller covered entities and offset project operators. A buyer liability rule implies a market in which invalidation would unleash a chain of contractual claims involving every party that ever held custody of the credit, paralyzing the marketplace. Aggregators and small businesses will avoid such a market—leaving a stunted offsets program involving only bilateral arrangements by largest covered entities for the largest projects. Small businesses and small projects will fall out of the equation. (IETA3)

Comment: MSCG has previously expressed its non-support for the concept of "buyer liability" with respect to offsets (section 95985). When ARB finds it necessary to invalidate a previously granted credit due to discovery of fraud or error, the holder of the credit at that point in time, or the compliance entity that previously submitted it for compliance, bears either the obligation for replacement (in the case of credits submitted for compliance) or economic loss (for those who hold an un-submitted credit). We think this is an inappropriate approach, but will not revisit such recommendations in detail. (MSCG3)

Comment: ConocoPhillips supports the proposal submitted by the International Emissions Trading Association (IETA), which involves a Compliance Buffer Account funded by a hold back of a certain percentage of credits from each offset project. CARB should also hold the responsible parties liable for making the system whole in the case of fraud or error. The IETA proposal, which is very widely supported by market participants including WSPA, would allow covered entitles to address risks associated with offsets and ultimately reduce costs related to compliance. (CONOCO2)

Comment: We and many others have identified problems with the "buyer liability" approach, and have supported an alternative—a compliance buffer account. (See Appendix C for the compliance buffer account proposal previously provided to ARB by CERP and a number of other organizations.)

Our central point is that any policy under which already issued offset credits can be invalidated will prevent the development of a market in offsets. The marketplace will not deal in instruments that are shadowed by the risk of invalidation and penalties. ARB's buyer liability rule will impose costs and risks on the offsets program that will strongly discourage the use of offsets and drive the program far closer to the "no-offsets" scenario—and, yet, will not provide any greater environmental integrity than a compliance buffer account or other similar approach that involves setting aside credits that can be retired in the event of offset credit problems.

In particular, the current proposed regulations require ARB to invalidate 100 percent of the offset credits issued for a project in a particular year if it determines that the Offset Project Data Report for that year was not "true, accurate, or complete." There is no materiality condition associated with this requirement. In other words, a minor inaccuracy or omission in a project's paperwork will cause ARB to invalidate all of the credits issued for the project—even if all of the emission reductions achieved by the project were 100 percent real, additional, and verified. This establishes an impossible, unfair, and unnecessary condition for offset projects—particularly in light of the extensive and detailed requirements for verification of projects (the general regulations include 18 pages of verification requirements, which do not include the additional requirements in the project-specific protocols).

There are several flaws with the buyer liability system. First, the approach is not fair. To be fair, a liability system should impose liability on the party actually responsible for the default. In the case of offset discrepancies, it almost certainly will be the offset project operator, the verifier, or the offset project registry that is at fault—and, under the cap-and-trade regulations, each of these parties makes attestations and submits to the jurisdiction of ARB. By contrast, the buyer of a credit will rarely if ever be responsible for a discrepancy related to offset credit issuance. Yet, under ARB's proposed buyer liability rules, the holder or user of a credit is presumptively liable. Liability shifts to the offset project operator only if the holder or user of the credit is no longer in business. This arrangement turns fairness on its head. To be clear, even most project developers would prefer a liability system in which liability rests with the party actually responsible for the discrepancy. (Indeed, ARB has adopted precisely this approach in the case of intentional reversals of forest projects, which we applaud.)

In addition, the buyer liability approach is highly inefficient. To be efficient, a liability system should impose liability on the party that has the most information and ability to control performance. Again, it is the offset project operator, verifier, and registry that have the greatest ability to avoid discrepancies—not the current holder of the offset credit. Accordingly, the buyer liability approach imposes additional and unnecessary transaction costs on the buyer of credits to protect itself against invalidation. (CERP4)

Comment: Some ARB officials have expressed a view that the buyer liability approach will reduce the risk of offset credit problems by creating incentives for buyers to scrutinize and avoid problematic sellers of offset credits. This view does not reflect the reality of how an offsets market works.

To be sure, covered entities have ample reasons to seek out scrupulous and competent sellers of offset credits—even without a buyer liability rule. Mainly, covered entities want to be assured that a seller is the kind of entity that will follow through on delivery of credits that are issued. However, covered entities are not well positioned to develop the kind of understanding of projects to allow them to discern whether claims of reductions are valid and that the project paperwork is 100 percent free of any errors. Companies that are in the business of electricity generation, refining, or cement manufacturing, for example, do not have any special insight into the business of methane digesters, ozone depleting substances, or forestry. In an offsets market, these companies will rely on the work of verifiers—and on ARB itself as credit issuer.

For this reason, making buyers liable for errors not detected by verifiers or the ARB itself will impose a substantial new cost and risk on buyers without materially reducing the risk of such events occurring. Buyers do not have added ability to avoid these events, short of incurring the costs of obtaining a second complete verification. If ARB truly seeks to reduce the risk of such occurrences, it should impose liability on the party actually responsible. (CERP4)

Comment: The Offset Buffer Account should be specified as a new account type, in section 95831. The Offset Buffer Account will be one of the accounts under the control of the Executive Officer. This proposed language, to be inserted into section 95831(b)

(p. 60), mirrors the existing language for the Forest Buffer Account. Modify section 95831(b) as follows:

> (b) Accounts under the Control of the Executive Officer. The accounts administrator will create and maintain the following accounts under the control of the Executive Officer: …
>
> > (7) A holding account to be known as the Offset Buffer Account:
> >
> > > (A) Into which ARB will place offset credits pursuant to section 95981.1; and
> > >
> > > (B) From which ARB may retire ARB offset credits pursuant to section 95985 and place them into the Retirement Holding Account. (SCPPA6)

Comment: Offsets should be deposited into the Offset Buffer Account, in section 95981.1. A step should be added to the offset credit issuance process in section 95981.1, under which ARB would hold back a portion of credits and place them in the Offset Buffer Account. The language mirrors the existing process for the Forest Buffer Account, but the percentage of the hold-back is specified in the Regulation. Modify section 95981.1(g) as follows:

> (g) Offset Buffer Account. ARB will place a portion of ARB offset credits issued to an offset project into the Offset Buffer Account.
>
> > (1) The amount of ARB offset credits that must be placed in the Offset Buffer Account shall be [1.5% of the amount issued to a project.]
> >
> > (2) ARB will transfer ARB Offset credits to the Offset Buffer Account at the time of ARB offset credit registration pursuant to section 95982.
> >
> > (3) If an offset project is originally submitted through an Offset Project Registry, an equal number of registry offset credits must be retired by the Offset Project Registry and issued by ARB for placement in the Offset Buffer Account. (SCPPA6)

Comment: In general, the proposed regulation assumes a system exists that would enable allowances to be auctioned, banked and traded, yet no system has been identified by CARB that would ensure the program is administered efficiently and accurately to protect the assets of the seller or buyer of credits. CARB staff suggests that buyers can be protected from bad credits through due diligence, the use of trained verifiers, or through the use of conveyance contracts. Although these measures may help protect the parties, they cannot be relied upon to protect the interests of the buyer and the needs of the market. (VALERO)

Comment: In our view, any approach to managing offset invalidation should meet four criteria: (1) it should ensure that the program is made environmentally whole; (2) it should be fair; (3) it should minimize costs to the offsets program; and (4) and it should minimize administrative burdens on ARB. For the reasons discussed above, the buyer liability approach may meet the first criterion, but substantially flunks the second two. Furthermore, it is not clear to us whether it imposes reasonable burdens on ARB because the effectiveness of buyer liability relies on ARB carrying out successful enforcement actions against potentially multiple buyers of credits from an affected project.

We and many others have advocated that ARB adopt an alternative approach: a compliance buffer account. ARB's expressed hesitations about this approach seem to us to underestimate the adverse impacts of the buyer liability approach and overestimate the administrative burdens and risks borne by ARB under a compliance buffer account approach.

In any event, we note that the proposed revisions to the regulations suggest that ARB is willing to adopt a variation on the compliance buffer account in the case of forest offsets. Though the approach does not conform precisely to the compliance buffer account mechanism supported by ourselves and others, we would greatly prefer ARB's use of this approach to the buyer liability system.

Under ARB's proposed regulations, ARB will hold back a certain amount of credits from each issuance of credits to a forest project. It will place these credits in a Forest Buffer Account. In the event of an "unintentional reversal" affecting the forest project, the already-issued credits will remain valid, but ARB will retire a corresponding number of credits in the Forest Buffer Account. In the event of an intentional reversal, the already issued credits again will remain valid, and ARB will require the forest owner (not a buyer) to deliver a corresponding number of compliance instruments credits from the forest owner (not the buyer). If the forest owner does not provide replacement instruments, ARB will cancel credits in the Forest Buffer Account.

We respectfully urge ARB to apply this approach for all offset projects. Compared to the buyer liability system, this approach would be: (1) equally effective in making the system whole in the event of invalid credits; (2) far fairer (by holding "bad actors" liable where possible); and (3) much more efficient (by effectively putting in place a system-wide, socialized insurance backstop). ARB has provided no reason that this kind of approach is workable and appropriate for forest offset projects, but not for other offset project types.

In particular, ARB has not explained why extending this approach to all offset projects establishes an unreasonable administrative burden on the agency. We do not believe such a burden would result. The primary role of ARB under the buffer account approach is to determine the portion of offset credits to set aside in the account. We believe this set-aside should be conservative. In any event, ARB would have the ability to increase the amount of the set-aside if the buffer account runs low.

Some ARB officials seem to have impression that "management" of the buffer account itself would impose burdens on the agency, and even require the employment of additional staff. This is incorrect. Once the set-aside amount is determined, the buffer account only exists for the purpose of retiring credits—which is an all but automated response to a finding of invalidation. The account requires no active management. It is not a bank account.

For these reasons, we urge ARB to expand the Forest Buffer Account concept to all offset credits. Modify sections 95802(a)(167) and 95831(b) as follows:

> (167) "Offset Buffer Account" means a holding account for ARB offsets credits. It is used as a general insurance mechanism against failure to surrender additional compliance instruments when ARB has made a determination pursuant to Section 95985(f). (CERP4)
>
> (b) Accounts under the Control of the Executive Officer. The accounts administrator will create and maintain the following accounts under the control of the Executive Officer.
>
> (7) A holding account to be known as the Offset Buffer Account:
>
> > (A) Into which ARB will place offset credits pursuant to section 95981.1; and
> >
> > (B) From which ARB may retire ARB offset credits pursuant to section 95985 and place them into the Retirement Holding Account. (CERP4)

Comment: SDG&E has concerns about ARB's "buyer liability" approach to addressing situations in which problems are identified with offset credits after they have been issued. The risk of such post-issuance problems is small because of the rigor of the ARB offset regulations. However, any policy under which already-issued offset credits carry a risk of invalidation will prevent the development of a well-functioning market in offsets. An unworkable offsets program that results in substantially less offsets being developed could have adverse consequences for the AB 32 program, as shown by ARB's own March 24, 2010 economic analysis. In order to develop a well-functioning offset market, buyer liability has to be eliminated. One way is to use the structure of the forestry offset buffer, but expand it to be a general offset buffer. The following proposed changes would be to implement an offset buffer in general rather than a specific forestry offset buffer. Modify sections 95802(a), 95831(b)(5), 95983, and 95985(g) as follows:

Section 95802(a)

> "~~Forest~~ Offset Buffer Account" means a holding account for ARB offset credits issued to ~~forest~~ ARB-approved offset projects. It is used as a general insurance mechanism against unintentional reversals, for all ~~forest~~ offset projects listed under a Compliance Offset Protocol.

Section 95831(b)

(5) A holding account to be known as the ~~Forest~~ Offset Buffer Account:

Section 95983 ~~Forestry~~ Offset Reversals.

(a) For ~~forest sequestration~~ offset projects, a portion of the ARB offset credits issued to the offset project will be placed by ARB into the ~~Forest~~ Offset Buffer Account.

(1) The amount of ARB offset credits that must be placed in the ~~Forest~~ Offset Buffer Account shall be determined as set forth in the relevant Compliance Offset Protocol ~~U.S. Forest Projects~~,

(2) ARB offset credits will be transferred to the ~~Forest~~ Offset Buffer Account by ARB at the time of ARB offset credit registration pursuant to section 95982.

(3) If an ~~forest~~ offset project is originally submitted through an Offset Project Registry an equal number of registry offset credits must be retired by the Offset Project Registry and issued by ARB for placement in the ~~Forest~~ Offset Buffer Account.

(b) Unintentional Reversals. If there has been an unintentional reversal, the Offset Project Operator or Authorized Project Designee must notify ARB and the Offset Project Registry, in writing, of the reversal and provide an explanation for the nature of the unintentional reversal within 30 calendar days of its discovery.

(1) In the case of an unintentional reversal the Offset Project Operator or Authorized Project Designee shall, provide in writing: to ARB and an Offset Project Registry, if applicable, a verified estimate of current carbon stocks within the offset project boundary within one year of the discovery of the unintentional reversal.

(2) If ARB determines that there has been an unintentional reversal, and ARB offset credits have been issued to the offset project, it ARB will retire a quantity of ARB offset credits in the amount of metric tons of CO_2e reversed from the ~~Forest~~ Offset Buffer Account.

(c) Intentional Reversals. Requirements of the Offset Project Operator or Authorized Project Designee for intentional reversals are as follows:

(1) If an intentional reversal occurs, the Offset Project Operator or Authorized Project Designee shall, within 30 calendar days of the intentional reversal:

(A) Give notice, in writing, to ARB and the Offset Project Registry, if applicable, of the intentional reversal; and

(B) Provide a written description and explanation of the intentional reversal to ARB.

(2) Within one year of receiving the notice for intentional reversal from ARB the occurrence of an intentional reversal, the Offset Project Operator or Authorized Project Designee shall submit to ARB and the Offset Project Registry, if applicable, a verified estimate of current carbon stocks within the offset project boundary.

(3) If an intentional reversal occurs from an ~~forest~~ offset project, the ~~forest~~ owner must replace each metric ton of CO_2e with a valid ARB offset credit

or another approved compliance instrument pursuant to subarticle 4, within 90 calendar days of notification by ARB. Notification by ARB will occur after the verified estimate of carbon stocks has been submitted to ARB, or after one year has elapsed since the occurrence of the reversal if the Offset Project Operator or Authorized Project Designee fails to submit the verified estimate of carbon stocks. If the ~~forest~~ owner does not replace each metric ton of CO_2e within 90 calendar days of notification by ARB, ARB will retire a quantity of ARB offset credits in the amount of metric tons of CO_2e reversed from the ~~Forest~~ Offset Buffer Account and the ~~forest~~ owner will be subject to enforcement action and each ARB offset
credit retired from the ~~Forest~~ Offset Buffer Account will constitute a separate violation pursuant to section 96014.

(4) In the event of an early ~~forest~~ offset project termination ARB will retire from the ~~Forest~~ Offset Buffer Account a quantity of ARB offset credits in the amount calculated pursuant to project termination provisions in Compliance Offset Protocol~~, U.S. Forest Projects [DATE]~~. ARB will notify the ~~forest~~ owner of retirement within 10 calendar days. The ~~forest~~ owner must submit a valid ARB offset credit or another approved compliance instrument pursuant to subarticle 4 for each ARB offset credit retired by ARB from the ~~Forest~~ Offset Buffer Account within 90 calendar days of ARB's retirement. If the ~~forest~~ owner does not replace each ARB offset credit within 90 calendar days of ARB's retirement, they will be subject to enforcement action and each ARB offset credit retired from the ~~Forest~~ Offset Buffer Account will constitute a separate violation pursuant to section 96014.

(d) Disposition of Offset ~~Forest Sequestration~~ Projects After an Unintentional Reversal. If a reversal lowers the ~~forest~~ offset project's actual ~~standing live~~ carbon stocks below its project baseline ~~standing live~~ carbon stocks, the ~~forest~~ offset project will automatically be terminated by ARB or an Offset Project Registry.

(1) If the ~~forest~~ offset project is automatically terminated due to an unintentional reversal, another offset project may be initiated and submitted to ARB or an Offset Project Registry for listing within the same offset project boundary.

(2) If the ~~forest~~ offset project has experienced an unintentional reversal and its actual ~~standing live~~ carbon stocks are still above the approved baseline levels, it may continue without termination as long as the unintentional reversal has been compensated by the ~~Forest~~ Offset Buffer Account. The offset project Offset Project Operator or Authorized Project Designee must continue contributing to the ~~Forest~~ Offset Buffer Account in future years as quantified in section 95983(a)(1).

(3) If the ~~forest~~ offset project is terminated due to any reason except an unintentional reversal, new offset projects may not be initiated within the same offset project boundary.

Section 95985

(g) Requirements for ~~Forest~~ Offset Projects contributing to the Offset Buffer Account. If an ARB offset credit is found to be invalid pursuant to sections 95985(b) and (d) for an ~~forest~~ offset project, the ~~Forest~~ Owner must replace each ARB offset credit with a valid ARB offset credit or another approved compliance instrument pursuant to subarticle 4, within 90 calendar days of being notification by ARB pursuant to section 95985(e). If the Forest Owner does not replace the invalid ARB offset credit within 90 calendar days of being notified by ARB pursuant to section 95985(e), each outstanding ARB offset credit will constitute a violation pursuant to section 96014. (SEMPRA3)

Comment: CantorCO_2e recommends that CARB amend the Regulation to create a CARB-administered insurance pool that is either privately funded with credits or through a CARB administered shave that is applied to each credit issued and/or traded. (CANTORCO2E2)

Response: We do not agree that we should eliminate buyer liability associated with the invalidation of ARB offset credits. Requiring the user to replace the invalidated offsets ensures that purchasers and users of offset credits do their due diligence in seeking out high-quality offset credits. We have clear enforcement authority over covered entities that will be using ARB offsets for compliance. If the covered entity replaces any invalidated offset credits, they may then take appropriate action through third-party contractual arrangements that they may have established prior to purchase. These arrangements currently exist in the voluntary offset market, and we expect that as the offset market becomes more established, that additional mechanisms to deal with the risk of invalidation will also be established. In the event that the offset credit has not yet been used or retired, it will be canceled in the market tracking system and removed from any Holding or Compliance Accounts. These provisions in no way diminish our authority to assess penalties under section 96014 on any offset project developer or verifier that has provided false information to ARB.

M-89. (multiple comments)
Comment: ARB proposes to look first to the current holder or compliance submitter for “replacement”, and if that entity is no longer in business, the offset project developer. MSCG believes this sequence is the reverse of what it should be. Upon invalidation, ARB should first notify the project owner of the invalidation, and inform it that it is obligated to replace both credits submitted for compliance, and credits in the accounts of existing holders. This obligation can be made part of the conditions imposed by the ARB for project approval and credit creation in the first instance. Only when the project owner is no longer in business, or is otherwise unable to replace invalidated credits, should ARB turn, in the second instance, to a compliance submitter to surrender replacement compliance instruments (a holder who owns credits which are invalidated, but have not yet been submitted in satisfaction of a compliance obligation, simply suffers an economic loss due to invalidation, and should not incur any “obligation to replace”, from ARB’s perspective). We strongly believe that the approach suggested

above is consistent with ARB's rationale for adopting a "buyer liability" approach, but would be a substantial improvement that significantly mitigates the flaws in buyer liability from the market's perspective. (MSCG3)

Comment: Assign offset liability to those that are best able to manage it, the project owner and CARB. Section 95985 states that users of credits which at the time of their acquisition were determined to be eligible for use that later turn out to be invalid are required to replace bad credits or suffer sanctions. Making the buyer liable for offset maintenance is problematic because buyers suffer sanctions and/or must replace credits that, though approved by the CARB, later turn out to be invalid; costs will be higher; and CARB will have fewer tools to guarantee environmental protection. An approach that relies purely upon the use of high quality credit verifiers will not work because verifiers are not officers of the government and do not have the ability determine if the credit creating activity meets the requirements of the rules as may be subsequently determined by the CARB; cannot (and are not paid to) monitor a project after the credits are claimed and/or transferred; will find it very challenging to secure professional liability insurance; and will only validate only the project data that is provided them. It will be difficult to write conveyance contracts in a fashion to remove buyer risk because credits may change hands many times; the actual credits may be divided, segmented, and conglomerated into financial instruments that allow market participants to transact products that represent emission reductions from a variety of different offset creating projects; and there is no guarantee that buyers will be in a position to purchase replacement credits. The problem of offset reversals cannot be adequately managed through the use of insurance or financial derivative products because such products may initially reduce the risk of purchasing offsets, but the instruments will, if priced considering consequential damages, sell at prices that dramatically increase transaction costs; and the insurance provider does not have the ability to understand, much less mitigate the potential financial consequences of offset reversals. (CANTORCO2E2)

> **Response:** We do not agree that the responsible party of an invalidated ARB offset credit should be the offset developer. We have clear enforcement authority over covered entities that will be using ARB offsets for compliance. If the covered entity replaces any invalidated offset credits, they may then take appropriate action through third-party contractual arrangements that they may have established prior to purchase. These arrangements currently exist in the voluntary offset market, and we expect that as the offset market becomes more established, that additional mechanisms to deal with the risk of invalidation will also be established. In the event that the offset credit has not yet been used or retired, it will be canceled in the market tracking system and removed from any Holding or Compliance Accounts. Requiring the user to replace the invalidated offsets ensures that purchasers and users of offset credits do their due diligence in seeking out high-quality offset credits.

M-90. Comment: Impose liability for the replacement of invalidated credits on the underlying project rather than on purchasers of such credits (section 95985). We continue to believe that the primary liability for replacing offset credits that have been invalidated by the Board should be imposed on the underlying project (the Offset Project Operator or Authorized Project Designee), as they are responsible for errors leading to invalidation. Such an approach has been used successfully in the Reserve's offset program and provides assurances that once a credit has been issued, it remains valid, while protecting the environmental integrity of the overall offset system. The draft regulation adopts this approach for forest projects in section 95985(g). We recommend that it be extended to all project types. Other mechanisms should only be considered if ARB is unable to obtain compensation from the project. (CAR4)

> **Response:** We do not agree that we should eliminate buyer liability associated with the invalidation of ARB offset credits. Requiring the user to replace the invalidated offsets ensures that purchasers and users of offset credits do their due diligence in seeking out high-quality offset credits. We do not agree that the responsible party of an invalidated ARB offset credit should be the offset developer. We have clear enforcement authority over covered entities that will be using ARB offsets for compliance. If the covered entity replaces any invalidated offset credits, they may then take appropriate action through third-party contractual arrangements that they may have established prior to purchase. These arrangements currently exist in the voluntary offset market, and we expect that as the offset market becomes more established, that additional mechanisms to deal with the risk of invalidation will also be established. In the event that the offset credit has not yet been used or retired, it will be canceled in the market tracking system and removed from any Holding or Compliance Accounts. Requiring the user to replace the invalidated offsets ensures that purchasers and users of offset credits do their due diligence in seeking out high-quality offset credits.

M-91. (multiple comments)
Comment: We believe the offset invalidation rules will further reduce the utility of offsets as a critical cost control mechanism. The ability of CARB to take 8 years to invalidate an offset covers the entire time period of the Cap and Trade program and essentially results in no time limits on reversals. This period should be reduced to 2 years in that regulated parties deserve timely due process and some degree of certainty that these purchased compliance instruments have value. (BP2)

Comment: Section 95985(b) gives ARB eight years to invalidate an offset credit. WSPA believes that eight years is too long a period for an offset to be invalidated. WSPA recommends that this section be amended to allow ARB only three years to invalidate offset credits. (WSPA3)

> **Response:** Section 95985(b) was modified to establish a statute of limitations for the invalidation of ARB offset credits of three years if the Offset Project Data Report or a subsequent Offset Project Data Report, depending on project type, is verified by a different verifier within that time frame. If the offset project does not qualify under these requirements, the default statute of limitations is eight years.

We believe that the three-year time period is sufficient to uncover any new information, as long as the project has been reviewed by a second verifier. If it is not looked at by a second verifier, we believe that eight years is necessary to uncover any new information that could lead to the invalidation of ARB offset credits. We believe the eight-year statute of limitations is sufficient because it would allow two verification parties to examine the offset credits in question for continuous projects.

M-92. Comment: Section 95985 provides that a California offset credit may be invalidated by ARB within 8 years of its issuance and that in that event, the user of that offset credit would be required to replace it with another compliance instrument. WPTF and many other stakeholders have consistently opposed such a "buyer liability" approach for offsets because it is unworkable. Buyers cannot manage the risk of credit invalidation and no insurance products exist now or are likely to emerge to fully mitigate this risk. Covered entities will almost certainly avoid using offsets altogether than be held presumptively liable for errors committed by another party such as an offset project operator, verifier, or registry. "Buyer liability" will drive the cap and trade program to a "no-offsets" scenario, which ARB has estimated would yield carbon prices of over $100 per ton and raise compliance costs by $18 billion in 2020. Rather than invalidating offsets after issuance, CARB should instead require that a portion of offset credits issued be deposited in an offset buffer account. In the event that any offsets are found deficient due to that entity's negligence or misconduct, the appropriate quantity would be retired from the buffer account. Offsets that have been issued would be unaffected. This approach would ensure that the environment is made whole in the event that offsets are deemed deficient, while providing certainty to offset buyers that all issued offsets could be used for compliance. (WPTF2)

Response: We do not agree that we should eliminate buyer liability associated with the invalidation of ARB offset credits. Requiring the user to replace the invalidated offsets ensures that purchasers and users of offset credits do their due diligence in seeking out high-quality offset credits. We have clear enforcement authority over covered entities that will be using ARB offsets for compliance. If the covered entity replaces any invalidated offset credits, they may then take appropriate action through third-party contractual arrangements that they may have established prior to purchase. These arrangements currently exist in the voluntary offset market, and we expect that as the offset market becomes more established, that additional mechanisms to deal with the risk of invalidation will also be established. In the event that the offset credit has not yet been used or retired, it will be canceled in the market tracking system and removed from any Holding or Compliance Accounts. These provisions in no way diminish our authority to assess penalties under section 96014 on any offset project developer or verifier that has provided false information to ARB.

Section 95985(b) was modified to establish a statute of limitations for the invalidation of ARB offset credits of three years if the Offset Project Data Report or a subsequent Offset Project Data Report, depending on project type, is verified by a different verifier within that time frame. If the offset project does not qualify under these requirements, the default statute of limitations is eight years. We believe that the three-year time period is sufficient to uncover any new information, as long as the project has been reviewed by a second verifier. If it is not looked at by a second verifier, we believe that eight years is necessary to uncover any new information that could lead to the invalidation of ARB offset credits. We believe that the eight-year statute of limitations is sufficient because it would allow two verification parties to examine the offset credits in question for continuous projects. We do not believe that one year would provide sufficient time to detect all relevant new information or uncover any mistakes that a verifier may have missed.

M-93. Comment: We are concerned that the proposed provisions in section 95985 for invalidating an offset up to eight years after its certification will undermine market stability, and add unnecessary and significant compliance costs. If a seller successfully performs all requirements determined by CARB to establish an offset and offers it for sale, and a buyer purchases an offset in good faith and with the certification of CARB that the offset is valid, that seller and buyer should not bear the risk of the State having committed an error in its evaluation and certification, or a change of law, regulation or policy that retroactively invalidates or devalues the offset. If the State of California cannot stand behind its offset validation system, the marketplace will not function. Placing the risk of invalidation on the seller will chill generation to the point that only those offsets that can be backed by significant security, most probably worth more than the offset itself, will enter the market. The cost of that security could vary widely, as the risk itself of purchasing an unknown quantity of offsets up to eight years in the future cannot be defined by either party. While there is legal precedent generally for buyers to shoulder the risk of devaluation of a product absent fraud on the part of the seller, an unconditional, eight-year guarantee of value placed on a seller is assigned in the very rare instances where not to do so would risk bodily harm or death to the purchaser. We recommend the Regulations separate fraud and intentional misrepresentation from all other circumstances that CARB believes might invalidate an offset. In the case of fraud, the fraudulent party should be liable for replacement of the offsets through contracts between offset buyers and sellers. However, absent fraud or intentional misrepresentation, the risk should fall squarely on the party establishing the Cap and Trade system, offset protocols and verification procedures. That is the State of California. This approach will provide the security essential for a strong and cost-effective Cap and Trade program. (WM3)

Response: We do not agree that we should eliminate buyer liability associated with the invalidation of ARB offset credits. Requiring the user to replace the invalidated offsets ensures that purchasers and users of offset credits do their due diligence in seeking out high-quality offset credits. We have clear enforcement authority over covered entities that will be using ARB offsets for compliance. If the covered entity replaces any invalidated offset credits, they may then take appropriate action through third-party contractual arrangements that they may have established prior to purchase. These arrangements currently exist in the voluntary offset market, and we expect that as the offset market becomes more established, that additional mechanisms to deal with the risk of invalidation will also be established. In the event that the offset credit has not yet been used or retired, it will be canceled in the market tracking system and removed from any Holding or Compliance Accounts. These provisions in no way diminish our authority to assess penalties under section 96014 on any offset project developer or verifier that has provided false information to ARB.

Section 95985(b) was modified to establish a statute of limitations for the invalidation of ARB offset credits of three years if the Offset Project Data Report or a subsequent Offset Project Data Report, depending on project type, is verified by a different verifier within that time frame. If the offset project does not qualify under these requirements, the default statute of limitations is eight years. We believe that the three-year time period is sufficient to uncover any new information, as long as the project has been reviewed by a second verifier. If it is not looked at by a second verifier, we believe that eight years is necessary to uncover any new information that could lead to the invalidation of ARB offset credits. We believe the eight-year statute of limitations is sufficient because it would allow two verification parties to examine the offset credits in question for continuous projects. We do not believe that one year would provide sufficient time to detect all relevant new information or uncover any mistakes that a verifier may have missed.

In addition, we included extensive modified provisions in section 95985 to make it clear what would trigger an invalidation, how ARB will invalidate offsets, and which offsets will need to be replaced. We believe that these changes provide clarity on this point.

M-94. Comment: Modify section 95985. These modifications would do the following:

- Reduce the statute of limitations for invalidation to the earlier of 8 years and the date that the project obtains a second verification.
- Eliminate from the conditions that could lead to invalidation a finding that the project documentation was not "true, accurate, or complete." This condition is overbroad and unnecessary given that there are other conditions that address errors that overstate emissions and failure to comply with legal requirements.
- Clarify that all entities involved with a project will be notified of a finding of invalidation.
- Require ARB to identify the entity responsible for the condition that resulted in identification.
- Require the responsible entity to provide replacement credits or face penalties. If the responsible entity fails to provide replacement credits, ARB will retire a corresponding amount of credits in the Offset Buffer Account. This language mirrors the existing language for the Forest Buffer Account.

- Allow the responsible entity six months (instead of 90 days) to replace credits; this approach is consistent with the provisions on liability for under-reporting of emissions.

(a) An ARB offset credit issued under this Article will remain valid ~~unless invalidated pursuant to sections 95985(b) and (c).~~ provided that, if ARB makes a determination pursuant to section 95985(b) then an additional compliance instrument must be surrendered in accordance with sections 95985(e).
(b) ARB may determine~~, within 8 years of issuance, except as provided in section 95985(b)(5) and 6, that an ARB offset credit is invalid for the following reasons:~~ at any time until the earlier of

(i) a post-issuance verification of the Offset Project Data Report by a different offset verifier or
(ii) 5 years ~~of~~ after issuance, that:

~~(1) ARB determines that information provided to ARB for an Offset Project Data Report or Offset Verification Statement by offset verifiers, verification bodies, Offset Project Operators, Authorized Project Designees, or Offset Project Registries related to an offset project was not true, accurate, or complete; or~~
~~(2)~~(1) The Offset Project Data Report contains errors that overstate the amount of GHG reductions or GHG removal enhancements by more than 5 percent (in which case, ARB shall determine the amount of offset credits that corresponds to the overstatement); or
~~(3)~~(2)The offset project did not meet all local, state, or national regulatory requirements during the time covered by an Offset Project Data Report; or
~~(4)~~(3)ARB determines that Offset credits have been issued in any other voluntary or mandatory program within the same offset project boundary or for the same GHG reductions or GHG removal enhancements covered by an Offset Project Data Report.
~~(5) If an offset project is developed under Compliance Offset Protocol U.S. Ozone Depleting Substances Projects, ARB may invalidate within five years of issuance of the ARB offset credits covered by an Offset Project Data Report.~~
~~(6) If an offset project is verified after three years of ARB offset credit issuance by a different offset verifier, ARB may invalidate within five years of issuance of the ARB offset credits covered by and Offset project Data Report~~
~~(7)~~(4)An update to a Compliance Offset Protocol in itself, will not result in an invalidation of ARB offset credits issued under a previous version of the Compliance Offset Protocol.

(c) If ARB ~~determines that an ARB offset credit is invalid~~ makes a determination pursuant to section 95985(b), ARB will:

(1) Identify all parties that may have some responsibility for the action that gave rise to the determination. Such parties may include:
~~(1)~~ (2) ~~Identify~~ The current holder of an ARB offset credit that has not been transferred to a compliance account or submitted for retirement;

~~(2)~~ (3) ~~Identify~~ The entity that holds an ARB offset credit in its compliance account or has submitted it for compliance or retirement; and

~~(3)~~ (4) The Offset Project Operator and Authorized Project Designee, and, if applicable, the Forest Owner~~, if applicable.~~

(d) ARB will notify the parties identified in section 95985(c) of the ~~invalidation~~ determination pursuant to section 95985(b) and provide ~~the~~ each party an opportunity to submit additional information to ARB ~~prior to invalidation~~ as follows:

(1) ARB will include the reason for the ~~invalidation of an ARB offset credit~~ determination pursuant to section 95985(b) in its notification to the part~~y~~ies identified in 95985(c).

(2) After notification the part~~y~~ies identified in 95985(c) will have 25 calendar days to provide any additional information to ARB.

(3) ARB may request any additional information as needed in addition to the information provided under this section.

(4) The Executive Officer will have 30 days after all information is submitted under this section to make a final determination ~~to invalidate an ARB offset credit~~ that one of the conditions listed pursuant to section 95985(b) has occurred, identify and notify the party responsible, and determine the number of offset credits affected and the compliance instruments that are required to be surrendered.

(e) Requirements for Surrender of Additional Compliance Instruments. If the Executive Officer ~~determines that an ARB offset credit is invalid~~ makes a determination pursuant to section 95985(b) and (d),

~~(1) The ARB offset credit will be invalidated and removed from any Holding or Compliance Account;~~

~~(2) The party identified pursuant to section 95985(c) will be notified of ARB's determination of invalidation pursuant to section 95985(d)(4);~~

~~(3) The Offset Project Operator or Authorized Project Designee, or the Forest Owner, if applicable, of the offset project for which the ARB offset credits were invalidated will be notified of ARB's determination of invalidation pursuant to section 95985(d); and~~

~~(4) Any approved program for linkage pursuant to subarticle 12 will be notified of the invalidation at the time of ARB's determination pursuant to section 95985(d)(4).~~

~~(f) Requirements for Non-Sequestration Offset Projects. If an ARB offset credit is found to be invalid pursuant to sections 95985(b) and (d), the party identified in section 95985(c)(2)~~ the party identified by ARB under 95985(c) ~~must replace each ARB offset credit with a valid ARB offset credit or another approved compliance instrument~~ must surrender the specified number of valid ARB offset credits or other approved compliance instruments pursuant to subarticle 4, within ~~90 calendar days~~ six months of notification by ARB pursuant to section 95985(e). If the party identified in section 95985~~(c)(2)~~(c)(1) does not ~~replace each invalid ARB offset credit~~ surrender the specified number of compliance instruments within ~~90 calendar days~~ six months of the notice ~~of invalidation~~ pursuant to section 95985(e), ~~each outstanding ARB offset credit will constitute a violation pursuant to section 96014.~~

(1) ARB will retire the specified quantity of ARB offset credits from the Offset Buffer Account; and

(2) the party will be subject to enforcement action pursuant to section 96014; and

(3) each ARB offset credit retired from the Offset Buffer Account will constitute a violation pursuant to section 96014. ~~If the party identified in section 95985(c)(2) is no longer in business ARB will require the Offset Project Operator or Authorized Project Designee to replace each invalidated ARB offset credit and will notify the Offset Project Operator or Authorized Project Designee that they must replace them. The Offset Project Operator or Authorized Project Designee must replace each ARB offset credit with a valid ARB offset credit or another approved compliance instrument pursuant to subarticle 4, within 90 calendar days of notification by ARB pursuant to section 95985(e).~~

~~If the Offset Project Operator or Authorized Project Designee does not replace each invalid ARB offset credit within 90 calendar days of notification by ARB pursuant to section 95985(e), each outstanding ARB offset credit will constitute a violation pursuant to section 96014.~~

~~(g) Requirements for Forest Offset Projects. If an ARB offset credit is found to be invalid pursuant to sections 95985(b) and (d) for a forest offset project, the Forest Owner must replace each ARB offset credit with a valid ARB offset credit or another approved compliance instrument pursuant to subarticle 4, within 90 calendar days of notification by ARB pursuant to section 95985(e). If the Forest Owner does not replace the invalid ARB offset credit within 90 calendar days of being notified by ARB pursuant to section 95985(e), each outstanding ARB offset credit will constitute a violation pursuant to 95985 96014.~~

~~(h)~~(f) Nothing in this section shall limit the authority of the State of California from pursuing enforcement action against any parties in violation of this article. (CERP4)

Response: We do not agree that we should eliminate buyer liability associated with the invalidation of ARB offset credits. Requiring the user to replace the invalidated offsets ensures that purchasers and users of offset credits do their due diligence in seeking out high-quality offset credits. We have clear enforcement authority over covered entities that will be using ARB offsets for compliance. If the covered entity replaces any invalidated offset credits, they may then take appropriate action through third-party contractual arrangements that they may have established prior to purchase. These arrangements currently exist in the voluntary offset market, and we expect that as the offset market becomes more established, that additional mechanisms to deal with the risk of invalidation will also be established. In the event that the offset credit has not yet been used or retired, it will be canceled in the market tracking system and removed from any Holding or Compliance Accounts. These provisions in no way diminish our authority to assess penalties under section 96014 on any offset project developer or verifier that has provided false information to ARB.

Section 95985(b) was modified to establish a statute of limitations for the invalidation of ARB offset credits of three years if the Offset Project Data Report or a subsequent Offset Project Data Report, depending on project type, is verified by a different verifier within that time frame. If the offset project does not qualify under these requirements, the default statute of limitations is eight years. We believe that the three-year time period is sufficient to uncover any new information, as long as the project has been reviewed by a second verifier. If it is not looked at by a second verifier, we believe that eight years is necessary to uncover any new information that could lead to the invalidation of ARB offset credits. We believe the eight-year statute of limitations is sufficient because it would allow two verification parties to examine the offset credits in question for continuous projects.

In addition, we included extensive modified provisions in section 95985 to make it clear what would trigger an invalidation, how we will invalidate offsets, and which offsets will need to be replaced. We believe that these changes provide clarity on this point.

We changed the timing for when the responsible party must replace the invalidated ARB offsets from 30 days to six months. This should provide enough flexibility for those that must replace invalidated offsets to purchase additional compliance instruments while still ensuing that the environmental integrity of the cap is maintained.

M-95. (multiple comments)
Comment: We strongly recommend ARB reconsider the concept of invalidating offset credits. This provision will threaten the use of offsets, investment in green projects, development of new technologies that California entrepreneurs are uniquely suited to provide, and if it does not destroy or significantly impair the market for offset projects, it will severely diminish transparency on any trades or transactions involving offsets. GreenX notes that verifiers are in a position of responsibility for invalid offsets. Each of the items identified in section 95985 as bases for invalidating an offset are items which are part of either the project verification to a methodology or the verification for issuance of credits. Subparagraph (b)(1) is a general incorporation of the requirements for obtaining ARB offset credits; (b)(2) seems to reflect the verifier requirements of proposed sections 95977 and 95977.1(b); Subparagraph (b)(3) appears vague and does not seem to add anything to (1) and (2) and the jurisdictions referenced likely would have their own remedies for any violations: and subparagraph (b)(4) we believe is already covered by (b)(1). Enforcement of the verifier and project proponent rules will achieve the very same result as attempted by the proposed section 95985. If there are issues discovered through a rotation of the verifiers, then the enforcement should be against those who created or verified the offset credit, those who would be liable for economic replacement of the invalidated credit. This approach would put the

accountability at the point of concern. We recommend the removal of section 95985. (GREENX)

Comment: The revision continues to propose that offset buyers be held liable in the event of offset reversals regardless of whether the reversal is intentional or unintentional. Failure to do so will constitute a violation resulting in CARB assessing penalties. CalChamber opposes buyer liability amongst the regulated entities and believes that enforcement of such liability ignores the purpose of approved offsets and a certification process supported by a third party verifier. Imposition of liability upon the buyer creates uncertainty that could raise transaction costs and suppress the market. It is reasonable to expect CARS, which approves every offset, to stand behind the offsets it approves, ensuring real, permanent and additional offsets without shifting any onerous liability burdens onto buyers. (CALCHAMBER3)

Comment: Section 95985 does not distinguish between situations in which errors in offset reporting are the result of an unintentional or "good faith" effort to be accurate, and those in which misstatements are intentional and fraudulent. We recommend that the cause of errors be bi-furcated, and the remedy for unintentional mistakes in offset reports be to 1) allow the verifier or offset operator the chance to correct the information; 2) create a buffer pool similar to the one used for unintentional reversals to allow for re-payment if errors result in an over-issuance of offset credits; and 3) if unintentional errors in offset data reports resulted in an under-issuance of credits, that correction to associated accounts be allowed and no invalidation occur.

For intentional or fraudulent actions leading to invalidation, we recommend that 1) the party responsible for the intentional error be held responsible (e.g., offset project operator, verifier, or registry) and required to replace the credits. Both the intentional commission of a fraud and failure to replace credits would be subject to substantial fines. If fraudulent reports are submitted by any party more than once, the party should be disqualified from participating in the ARB offset program. (PFT3)

Comment: The standard for invalidation of ARB offset credits provided in section 95985 is too broad, and in the case of forestry projects, the locus of responsibility for replacement is too narrow. As written, this rule will significantly deter forestry offset project development. A preferred approach would mirror the approach used to replace offsets lost to reversals. For example, section 95985(b) provides that offsets may be invalidated if "information provided to ARB for an Offset Project Data Report or Offset Verification Statement by offset verifiers, verification bodies, Offset Project Operators, Authorized Project Designees or Offset Project Registries related to an offset project was not true, accurate, or complete." Our experience with the verification process is that good faith errors may occur in the course of a given verification. These errors may occur at any point in the course of project development, verification, or registration. While our experience also indicates that these errors are identified and rectified in subsequent verifications, the penalties in the proposed invalidation procedure would already have been levied. This outcome is particularly onerous in the case of a forest project because section 95985(g) imposes the obligation for replacement solely on the forest project developer irrespective of where in the chain of production the error occurred. ARB should consider an approach to invalidation similar to that used for replacement of offsets lost to a reversal. Specifically, ARB should distinguish between an “unintentional invalidation” and an “intentional invalidation”. An intentional invalidation would be any offset invalidated due to negligence, gross negligence or fraud. In such a case, responsibility for replacement would be similar to that required for intentional reversals in connection with forestry projects (section 95983(c)). To cover unintentional invalidations, ARB should consider requiring offset projects to contribute to a buffer pool in a percentage appropriate to the type of project and potential for good faith errors. The buffer pool would be used to retire the number of tons deemed to be invalid. Alternatively, in the case of unintentional invalidations, ARB could consider allowing a project developer to replace the invalidated offsets by making contributions from offsets issued in future verifications of the project. (TCF2)

> **Response:** We do not agree that we should eliminate buyer liability associated with the invalidation of ARB offset credits. Requiring the user to replace the invalidated offsets ensures that purchasers and users of offset credits do their due diligence in seeking out high-quality offset credits. We have clear enforcement authority over covered entities that will be using ARB offsets for compliance. If the covered entity replaces any invalidated offset credits, they may then take appropriate action through third-party contractual arrangements that they may have established prior to purchase. These arrangements currently exist in the voluntary offset market, and we expect that as the offset market becomes more established, that additional mechanisms to deal with the risk of invalidation will also be established. In the event that the offset credit has not yet been used or retired, it will be canceled in the market tracking system and removed from any Holding or Compliance Accounts. These provisions in no way diminish our authority to assess penalties under section 96014 on any offset project developer or verifier that has provided false information to ARB.
>
> We included extensive modified provisions in section 95985 to make it clear what would trigger an invalidation, how we will invalidate offsets, and which offsets will need to be replaced. We believe that these changes provide clarity on this point.

M-96. Comment: NextERA urges ARB to eliminate the “buyer liability” provision in the Regulation. NextEra strongly believes that once an offset credit is verified and certified, it should remain viable and non-revocable. In section 95985, ARB provides a mechanism for the invalidation of certified offset credits. The purchaser the offset credit assumes a “buyer liability” and would be required to replace any invalidated offsets used for compliance with either another certified offset or an allowance. We urge ARB to change section 95985 and eliminate the “buyer liability” imposed on purchasers of offset credits. The viability of the offset credit should be the responsibility of the certification process, registered certifying agents, and the offset provider. In many cases the purchaser of the offset credit will be completing transactions through a third party and not be directly involved with the offset project. The purchaser should be able to trust the certification process developed by ARB to assure what they are buying is a real reduction in GHG emissions and that it qualifies for use as a compliance tool in the GHG Cap and Trade program. The criteria established by ARB to allow offsets for use under the Regulation state that reductions qualifying for offsets must be permanent. The ability of ARB to invalidate a certified offset at a future date contradicts that criterion. The mechanism for the verification and certification of offset credits needs to supply the purchaser with the confidence that the credit they are purchasing will remain viable for use to meet a compliance obligation in future years. The ability of ARB to revoke the viability of an offset implies that anyone who uses offsets to meet a compliance obligation remains in a tentative state of compliance for a period of up to eight years. This has potential implications that could affect the value of or risk associated with an asset on a rolling 8 year schedule. Once a compliance obligation is met using certified compliance instruments, it is not acceptable from a risk perspective that a facilities compliance status can then be reversed. Failure to provide assurance that a certified offset is reliable could lower demand for offsets and in turn discourage investment in offset projects. An unnecessary element of risk would be added into every offset transaction. In addition, this risk could affect property values, asset transactions, and credit evaluations. These added risks and the liability to buyers of invalidation are unnecessary and should be removed from the Regulation. (NEXTERAENERGY2)

> **Response:** We do not agree that an offset credit should remain viable under all conditions. To ensure the enforceability of compliance offsets, we need to have the ability to investigate and take action for violations or noncompliance with the proposed regulation. In the event of fraud or malfeasance on the part of project developers or verifiers, there may be cause to invalidate offset credits after they have been issued, to protect the environmental integrity of the program. These provisions in no way diminish our authority to assess penalties under section 96014 on any offset project developer or verifier that has provided false information to ARB.
>
> Section 95985(b) was modified to establish a statute of limitations for the invalidation of ARB offset credits of three years if the Offset Project Data Report or a subsequent Offset Project Data Report, depending on project type, is verified by a different verifier within that time frame. If the offset project does not qualify under these requirements, the default statute of limitations is eight years. We believe that the three-year time period is sufficient to uncover any new information, as long as the project has been reviewed by a second verifier. If it is not looked at by a second verifier, we believe that eight years is necessary to uncover any new information that could lead to the invalidation of ARB offset credits. We believe the eight-year statute of limitations is sufficient because it would allow two verification parties to examine the offset credits in question for continuous projects.

M-97. (multiple comments)
Comment: We recognize the effort made to create a shorter period of liability for the invalidation of offset credits. However, we remain concerned that the liability provisions

as presently written will deter emitters from using offset credits as a compliance option, because emitters will neither be able to estimate nor control the resulting financial exposure. Further, while we might expect emitters to contractually assign the liability to other parties, this practice will not eliminate the liability nor the cost, as the ARB would still enforce against the emitter and legal action would be required for the emitter to attempt to recoup its costs from other parties in the offset chain of custody. We recommend that the Board adopt some mechanism by which an offset credit can be deemed permanently valid as soon as possible after the verification period. We have several suggestions along these lines:

- Eliminate future liability for credits that undergo simultaneous (or directly subsequent) verifications by two different verifiers, and submit both verifications to the ARB prior to issuance. This would give buyers and project developers an option to eliminate the invalidation risk for a given vintage or project at additional cost; or
- In addition to releasing liability after three years of issuance and a subsequent verification by a new verifier as currently proposed, release liability after 1 year of issuance and a subsequent verification by a new verifier, if that the new verifier audits the previously verified credits. Specifically, the new verifier would be required to conduct a desk review and as warranted a full re-verification of the previously verified credits, using the same rules as specified for the re-verification of Early Action offset credits.
- With this suggestion in mind, we recommend that Early Action offset credits which are transferred to the ARB having undergone a second verification (once for the original offset program, and once for the ARB compliance review) should not carry any risk of invalidation. (TPI5)

Comment: Section 95985(b)(1) allows ARB to invalidate an offset within 8 years of issuance if ARB has determined that information provided to ARB related to an offset project "was not true, accurate, or complete." SCE requests that ARB add further detail on what is meant by "true or accurate." As currently written, ARB could reverse offsets for even clerical errors. SCE believes that this is not the intent of this provision, and requests that ARB clarify these provisions. Furthermore, in the event that ARB chooses to reverse an offset as a result of information that is not true or accurate, ARB should first require that the entity most directly responsible for the incorrect information or fraud to retire instruments equal to the offset in question. The Regulation should clearly state that in the event that ARB is able to obtain replacement compliance instruments from the "bad actor" project developer or verifier, these replacement compliance instruments will be retired by ARB, leaving the validity of the original offsets unchanged. In this way, the environmental integrity of the program persists without undue hardship to downstream purchasers of offsets from these projects. (SCE3)

> **Response:** We do not agree that an offset credit should remain viable under all conditions. To ensure the enforceability of compliance offsets, we need to have the ability to investigate and take action for violations or noncompliance with the proposed regulation. In the event of fraud or malfeasance on the part of project developers or verifiers, there may be cause to invalidate offset credits after they

have been issued, to protect the environmental integrity of the program. These provisions in no way diminish our authority to assess penalties under section 96014 on any offset project developer or verifier that has provided false information to ARB.

Section 95985(b) was modified to establish a statute of limitations for the invalidation of ARB offset credits of three years if the Offset Project Data Report or a subsequent Offset Project Data Report, depending on project type, is verified by a different verifier within that time frame. If the offset project does not qualify under these requirements, the default statute of limitations is eight years. We believe that the three-year time period is sufficient to uncover any new information, as long as the project has been reviewed by a second verifier. If it is not looked at by a second verifier, we believe that eight years is necessary to uncover any new information that could lead to the invalidation of ARB offset credits. We believe the eight-year statute of limitations is sufficient because it would allow two verification parties to examine the offset credits in question for continuous projects. We do not believe that one year would provide sufficient time to detect all relevant new information or uncover any mistakes that a verifier may have missed.

M-98. Comment: Reduce the offset project invalidation to one year. The invalidation of an offset credit due to "The offset project did not meet all local, state, or national regulatory requirements during the time covered by an Offset Project Data Report;" does not need to be in the Regulation. This provision is too broad and exponentially increases the risk to offset generators and buyers. The reasons given for potential invalidation in this section are potentially not even related to the validity of the offsets generated by a project. For instance, according to the current wording to the Regulation, if a property fence surrounding the project is not properly placarded the project triggers the criteria for invalidation. We hope that this is merely an oversight on ARB's part and not their intent. In order to avoid this type of scenario, section 95985(b)(3) should be eliminated. Financial or regulatory status of a project can be added to the verifier's criteria for project verification but we feel that this section is unnecessary. Again NextEra feels that ARB should be proactive when addressing this issue and not reactive. (NEXTERAENERGY2)

Response: We included extensive modified provisions in section 95985 to make it clear what would trigger an invalidation, how we will invalidate offsets, and which offsets will need to be replaced. We believe that these changes provide clarity on this point.

Section 95985(b) was modified to establish a statute of limitations for the invalidation of ARB offset credits of three years if the Offset Project Data Report or a subsequent Offset Project Data Report, depending on project type, is verified by a different verifier within that time frame. If the offset project does not qualify under these requirements, the default statute of limitations is eight years. We believe that the three-ear time period is sufficient to uncover any new information, as long as the project has been reviewed by a second verifier. If it is not looked at by a second verifier, we believe that eight years is necessary to uncover any new information that could lead to the invalidation of ARB offset credits. We believe the eight-year statute of limitations is sufficient because it would allow two verification parties to examine the offset credits in question for continuous projects. We do not believe that one year would provide sufficient time to detect all relevant new information or uncover any mistakes that a verifier may have missed.

M-99. (multiple comments)
Comment: We urge ARB to revisit the provisions related to "overstatement" to avoid unnecessarily punitive outcomes.

The rules provide that one of the grounds of invalidation of offset credits is a finding that an offset project data report "overstate the amount of GHG reductions or GHG removal enhancements by more than 5 percent"—irrespective of whether such overstatement resulted from malfeasance or good faith error.

It is unclear from the rules themselves what penalty flows from such an occurrence. However, we have learned from ARB staff that a finding of more than 5 percent overstatement will result in invalidation of all of the credits issued in connection with the data report. In other words, in the event of an overstatement of 6 percent, ARB would invalidate 100 percent of the credits associated with the report—even though 94 percent of the reported reductions would be real, additional, and verifiable. It is this kind of draconian rule that will dissuade many entities (and insurers) from even participating in the offsets program.

ARB officials have explained that they have adopted this approach because the invalidation system only includes a step in which there is a general determination of material misstatement, and does not include a second step of determining the specific amount of the overage. We believe that it is only consistent with due process and fairness to penalize only the actual overage. We would support adding a step in the process that make such a precise determination of liability possible—even if it necessitates required cooperation by the offset project operator and a new verifier.

ARB officials also have said that they are reluctant—under a buyer liability system—to penalize only some holders of credits from a particular year and not others. Yet, such an outcome is not necessary. If ARB retains the buyer liability approach—which, again, we strongly oppose—we recommend that ARB apply the overage penalty on a pro rata basis to all holders of credits from the relevant vintage year. See the following example:

a. For a particular offset project, two entities are holders or users of credits issued in a particular vintage year: Entity A (60 percent of credits) and Entity B (40 percent of credits).

b. ARB subsequently finds a material misstatement for the project of 1000 tons.

c. ARB invalidates 600 of Entity A's credits and 400 of Entity B's credits.

We believe such a pro rata approach is fair and efficient. (CERP4)

Comment: Section 95985(b)(2) should be drafted with greater clarity to ensure its consistency with AB 32 and the proposed regulations as a whole. The regulations should unequivocally state that a finding of greater than a 5 percent overstatement in a project will not result in the invalidation of all offset credits from that project. The regulations should clearly state that only the overstated amounts are subject to invalidation. ARB must remain true to the regulatory principle that serialized offset credits representing real, additional, permanent, quantified, and verified emission reductions are valid. Each serialized offset credit should stand on its own. In sum, ARB has no authority to invalidate registered offset credits that are in full compliance with the regulations. (OFFSETSWG3)

Comment: It is PG&E's understanding that if an Offset Project Data Report contains errors that overstate reductions or removals by more than five percent, it will result in invalidation of all credits associated with that report, not just the overage. PG&E feels this is overly burdensome and unnecessary to maintain environmental integrity. It implies that the over-crediting of a project means that all the credits from the given vintage should not have been issued. PG&E believes that the conservative protocols and rigorous verification and issuance process should eliminate projects that could have the potential for over-crediting. Modify section 95985 as follows:

(a) An ARB offset credit issued under this Article will remain valid: unless invalidated pursuant to sections 95985(b) and ~~(c)~~ (d).
(b) ARB may determine ~~within~~ by no later than a date that is the earlier of a post-issuance verification of the Offset Project Data Report by a different verifier and 8 years ~~of~~after issuance, except as provided in section 95985(b)(5) and (6), that an ARB offset credit is invalid for the following reasons:

(1) ARB determines that information provided to ARB by verifiers, verification bodies, Offset Project Operators, Authorized Project Designees, or Offset Project Registries, related to an offset project was not true, accurate, or complete; or
(2) ~~The Offset Project Data Report contains errors that overstate the amount of GHG reductions or GHG removal enhancements by more than 5 percent; or~~
~~(3)~~ The offset project did not meet all local, state, or national regulatory requirements during the time covered by an Offset Project Data Report; or
(4) ARB determines that offset credits have been issued in any other voluntary or mandatory program within the same offset project boundary or for the same GHG reductions or GHG removal enhancements.
(5) If an offset project is developed under Compliance Offset Protocol U.S. Ozone Depleting Substances Projects, ARB may invalidate within five

years of issuance of the ARB offset credits covered by an Offset Project Data Report.
(6) If an offset project is verified after three years of ARB offset credit issuance by a different offset verifier, ARB may invalidate within five years of issuance of the ARB offset credits covered by an Offset Project Data Report.
(7) An update to a Compliance Offset Protocol in itself, will not result in an invalidation of ARB offset credits issued under a previous version of the Compliance Offset Protocol. (PGE4)

Comment: At the July 15 workshop MSCG raised an issue that is not addressed by the current draft of the rule. When less than 100 percent of the credits are invalidated, which credits are selected for invalidation? For example, suppose it is realized that an inadvertent error in a calculation algorithm caused a project's emissions reductions to be systemically overstated by 10 percent for the first three years of the project. Presumably, the remedy would be to invalidate 10 percent of the credits issued from that period. How would ARB determine which 10 percent to invalidate? This question has major equity issues associated with it. Depending on how it is handled, a single entity could suffer a hugely disproportionate economic lost due to invalidation. When the issue was briefly discussed at the workshop, staff stated that it believed it had a methodology devised that would address this issue. However, this methodology has not yet been made public. We believe that the methodology should be explicitly included in the rule, and that prior to final adoption, it needs to be vetted through a stakeholder process to get input with regard to possible oversights and flaws, and at least attempt to obtain stakeholder consensus with regard to the method adopted being the best available approach. (MSCG3)

Response: We included extensive modified provisions in section 95985 to make it clear what would trigger an invalidation, how we will invalidate offsets, and which offsets will need to be replaced. We believe that these changes provide clarity on this point.

In addition, we included new section 95985(c)(1)(A)), which includes provisions for ARB to invalidate the overage of credited GHG reductions and GHG removal enhancements. Under this provision, we will only invalidate the number of ARB offset credits that correspond to the overstated GHG reductions and GHG removal enhancements and not 100 percent of the ARB offset credits in that Offset Project Data Report. We also included a procedure for how we will determine which serial numbers we will invalidate. We believe this approach will maintain the environmental integrity because any overage will immediately be compensated. These provisions address stakeholder concerns that projects will be unfairly penalized for small calculation mistakes.

M-100. (multiple comments)

Comment: We have strong concerns about ARB's "buyer liability" approach to addressing situations in which problems are identified with offset credits at some point after issuance. (See generally section 95985.) The risk of such post-issuance problems is very small due to the rigor of the ARB offset regulations. However, any policy under which already-issued offset credits carry the risk that they may be invalidated will prevent the development of a market in offsets. The buyer liability approach is neither fair nor efficient. In the case of offset discrepancies, it almost certainly will be the offset project operator, verifier, or offset project registry that is at fault. All of these parties are subject to ARB enforcement, as each must affirmatively submit to ARB's jurisdiction in order to participate in the program. Yet, under ARB's proposed buyer liability rules, it is the holder or user of a credit that is presumptively liable for any discrepancy. This arrangement turns fairness on its head. The approach also is highly inefficient. To be efficient, a liability system should impose liability on the party that has the most information and ability to control performance. Most covered entities do not have any special insight into methane digesters, ozone-depleting substances, or forestry, and it will be costly for them to double-check the quality of the offset credits. In an offsets program, covered entities should be able to will rely on the work of verifiers—and on ARB itself as credit issuer. For this reason, making covered entity buyers liable for problems not detected through the regulatory system will impose substantial new costs on buyers without materially reducing the risk that such problems will occur. ARB has suggested that buyers can easily manage their liability risk through contracts. This is simply not consistent with marketplace realities. A viable offsets program will involve the participation of many buyers and sellers—including aggregators that mediate between smaller covered entities and offset project operators. A buyer liability rule would unleash a chain of potential contractual claims involving every party that ever held custody of the credit. Aggregators and small businesses will avoid such a market—leaving a stunted offsets program involving only bilateral arrangements between the largest covered entities and the largest offset projects. Small businesses and small projects will fall out of the equation.

The buffer account approach should be applied to all offsets. The Regulation includes a buffer account to address post-issuance problems associated with forest offset projects. We strongly urge ARB to apply the approach of this Forest Buffer Account to all offset projects. This approach would be just as effective at ensuring the integrity of the program as the buyer liability system, as it would ensure that the system would be made whole in the event of invalid credits. It would be easier for ARB to manage, as it would need only to withdraw credits from the buffer account in order to make the system whole. There would be no need to make demands upon an unlucky (and unhappy) user of credits that have been invalidated after issuance. It also would be far more fair, as it would hold "bad actors" liable where possible rather than unlucky purchasers of credits. The buffer account's approach of a system-wide backstop would enable the market as a whole to manage the risk of post-issuance invalidation in an efficient manner that also would be more effective and more fair. Applying this buffer account approach to all offset projects would not impose unreasonable administrative or risk burdens on ARB. The primary role of ARB would be to determine the portion of offset credits to set aside in the account. As the risk of invalidation is extremely low due to the rigor of ARB's program leading up to issuance, we believe the set-aside would be quite conservative. However, ARB would have the ability to increase the amount of the set-aside if the buffer account runs low. Finally, as noted above, in the event of invalidation, ARB need only withdraw credits from the account to make the program whole. The account requires no active management—and no need to make demands on the unlucky holders of invalidated credits, demands that may well be contested. (COPC3)

Comment: In section 95985 of the proposed rule, ARB has made several modifications and clarifications to the mechanism for the invalidation of offset credits. While Evolution Markets appreciates these changes, we continue to believe the process for invalidating offset credits and resting the liability for replacing the credits solely with the buyer introduces an unacceptable element of uncertainty to the offset market. The result could be a reluctance of market participants to invest in offset projects and a difficulty in creating necessary liquidity in secondary offset markets, which makes low-cost offsets available to all compliance entities. In fact, Evolution Markets sees the impacts of these regulations in the market today. As an intermediary assisting counterparty investment in offset credits, we have seen a noticeable slowdown in the flow of capital to early action-eligible offset projects. The inability to complete transactions has often been directly attributable to uncertainty resulting from ARB's "buyer liability" approach. Such an approach is unprecedented in offset markets, and counterparties have not been able to address the extended risk associated with purchasing or selling offset credits. We have seen transactions break down as buyers have requested guarantees against invalidation that sellers are unwilling and unable to provide. And, we have seen investments fall through as both buyers and sellers seek to address invalidation risk post-deal confirmation. The market activity (or lack thereof) in early action offset credits in recent months demonstrates to ARB that its assumption that market participants will be able to address the invalidation liability issue through contracts does not bear out. Furthermore, this experience should raise concern at ARB that these provisions might be having a direct impact on offset supply, and perhaps could lead to higher costs for compliance. We recommend ARB strongly consider the Compliance Buffer Account approach presented by the industry coalition led by the International Emissions Trading Association, or at the very least open a dialogue with industry representatives on a viable alternative. (EVMKTS2)

Comment: The process for potential invalidation of offsets creates large, uninsurable risks for project developers. Only the largest developers will be able to develop projects, further restricting an already limited offset market. PG&E suggests use of a compliance buffer account and dual verifications to ensure the environmental integrity of offsets while encouraging the development of offset projects. (PGE4)

Comment: Invalidation of issued offsets and the current designation of liability will interfere with the development of an efficient and cost effective offset market.
The focus of ARB's rules related to offsets should be on rigorous verification and certification standards to ensure that only quality credits enter the market. If stringent requirements are established, the need to invalidate credits would be rare. Once credits

are certified by ARB, invalidation of the credits should be an extraordinary occurrence. However, if ARB finds it necessary to retain the option of invalidation, a buffer account should be established for all credit categories, similar to the buffer account for forestry projects. For example, ARB could implement an insurance pool where a small part of allowances and/or credits are banked and set aside only to be drawn upon in the event that an extraordinary reversal cannot be otherwise resolved. (TCT)

Comment: The Joint Utilities believe that the provisions of section 95985 regarding "buyer liability" for post-issuance invalidation of offsets would hinder the ability of the offsets program to function efficiently and jeopardize the program's emissions reduction goals. Instead of imposing buyer liability, the Joint Utilities recommend that CARB apply a "buffer" account approach for all types of offset projects. (JOINTUTILITIES)

Comment: We recommend adding a step to the credit issuance process under which ARB would hold back a portion of credits and place them in the Offset Buffer Account. The language mirrors the existing process for the Forest Buffer Account, but allows ARB to specify the percentage of the hold-back and provides a recommended percentage. It also allows ARB to increase or decrease the percentage to ensure that the amount of credits in the Offset Buffer Account is sufficient to address any invalidations. Modify section 95981.1(g) as follows:

> (g) Offset Buffer Account. A portion of ARB offset credits issued to an offset project will be placed by ARB into the Offset Buffer Account.
>
> > (1) The amount of ARB offset credits that must be placed in the Offset Buffer Account shall be [1.5 percent] of the amount issued to a project; provided that ARB shall increase this percentage if ARB determines that the amount of offset credits in the Offset Buffer Account is less than [1.5 percent] of the number of offset credits issued in the previous five years, and ARB shall decrease the percentage if the amount in the Offset Buffer Account is more than [1.5 percent] of the number of offset credits issued in the previous five years. Any such modification to the percentage placed in the Offset Buffer Account shall apply to offset projects listed or starting a new crediting period after the date of the modification.
> > (2) ARB Offset credits will be transferred to the Offset Buffer Account by ARB at the time of ARB offset credit registration pursuant to section 95982.
> > (3) If an offset project is originally submitted through an Offset Project Registry, an equal number of registry offset credits must be retired by the Offset Project Registry and issued by ARB for placement in the Offset Buffer Account. (CERP4)

Comment: CLFP believes the buyer offset liability language is problematic because buyers suffer sanctions or must replace credits that, though approved by the CARB, later turn out to be invalid. As a result, offset transaction costs will be higher than need be, programmatic compliance costs will be higher, offsets are likely to be considered to be second class compliance instruments by the market; and sources on the margin will be that much more inclined to expand their operations and/or export jobs outside the jurisdiction of AB 32 due to higher costs. Standard seller liability is used in all other Cap and Trade programs in the US and EU. CARB has suggested that a "buyer beware" approach will suffice, one utilizing exhaustive due diligence, the deployment of trained verifiers, or even the use of cleverly written conveyance contracts and sophisticated derivative products. It will not work, especially in situations where a credit may be created and then sold a number of times before it is used and applied. Instead, buyer liability will more than likely raise transaction costs. Nor should CARB conclude that the problem of offset reversals can be managed through the use of insurance or financial derivative products. While such products may initially reduce the risk of purchasing offsets the instruments, if priced based on risk, will sell at prices that dramatically increase transaction costs. CLFP recommends that CARB amend the language to give buyers an opportunity to avoid liability by:

- Allowing a source to secure CARB/air district review and approval of credits. This is how it has been done for decades in California with offsets that have been useable for new source review compliance purposes.
- CARB/air district issuance of permits to offset creating sources. Again, consider the NSR example.
- Creating an insurance pool that is either privately funded with credits or through a CARB administered shave that is applied to each credit issued and/or traded. (CALFP3)

Comment: If ARB is concerned that certain invalidation factors may only come to light after a period of time, we suggest that the ARB separate the requirement to replace invalidated credits from the ARB's other enforcement capabilities:

- We recommend that initial double verifications or subsequent re-verifications as described above release any credit holder from a requirement to replace those credits if they are invalidated thereafter.
- In such case, the ARB could retain the right under its pervasive enforcement authority to take actions against the offset project developer, the offset verifier, or the offset project owner, all of whom will have submitted themselves to ARB jurisdiction, should the project's credits become suspect. At its option, the ARB could choose to levy fines sufficient to purchase replacement credits, or could require the surrender of replacement credits in addition to fines and other penalties levied in such enforcement actions. (TPI5)

Comment: We urge ARB not to include section 95985 as proposed. Invalidation of offsets credits will threaten the use of offsets, investment in green projects, development of new technologies that California entrepreneurs are uniquely suited to provide, and, if it does not destroy or significantly impair the market for offset projects, it will severely diminish transparency on any trades or transactions involving offsets. If there are issues discovered through a rotation of the verifiers, the enforcement should be against those who created or verified the offset credit, and would be liable for economic replacement of the invalidated credit. This approach would put the accountability at the point of concern. The issues identified by proposed section 95985 are each issues that the project proponent and/or the verifier for the project are in the best position to not only have the facts, but also to advocate their views. Verifiers will want to protect their reputation and thus have a vested interest in verifying only quality offsets. In addition, this risk of a penalty may be able to be addressed through insurance coverage by the verifier, and the costs of riskier projects that may require higher insurance can be passed on via fees to the project developer. We recommend removing section 95895. If ARB wishes to retain the concept of invalidating issued ARB offset credits, provide an exemption step for the Offset Project Operator and/or the Authorized Project Designee so either (or the verifier) can choose to avoid the sanctions threatened by section 95985 and risk of liability years after the offset credit was created. Any project which has had a second verifier review the project, such as the requirements proposed in section 95977.1 for rotation to a new verifier, should be exempt from the threat of invalidation. We believe such is an unnecessary extra cost for projects, but it is far better than putting the market at risk because of the vague and uncertain threat of proposed section 95985. In lieu of this exemption or "safe harbor" concept, we also would support the buffer pool concept as proposed by IETA. In addition to the above, or perhaps as an alternative, remove the buyer liability terms and put the onus squarely on the entities that put the credit into the compliance market. Modify section 95985(c) and (f) as follows:

> (c) If ARB determines that an ARB offset credit is invalid pursuant to section 95985(b), ARB will~~:–~~identify the Offset Project Operator, the Authorized Project Designee and the verifier(s) of the offset credit in question. ~~the current holder of the ARB offset credit or the entity that submitted the ARB offset credit for compliance or retirement.~~
>
> > ~~(1) Identify the current holder of an ARB offset credit that has not been transferred to a compliance account or submitted for retirement;~~
> > ~~(2) Identify the entity that holds an ARB offset credit in its compliance account or has submitted it for compliance or retirement; and~~
> > ~~(3) The Offset Project Operator and Authorized Project Designee, and Forest Owner, if applicable.~~
>
> (f) Requirements for Non-Sequestration Offset Projects. If an ARB offset credit is found to be invalid pursuant to sections 95985(b) and (d), the part~~y~~ies identified in section 95985(c) must replace each metric ton of CO_2e with a valid ARB offset credit or another approved compliance instrument pursuant to subarticle 1 within 90 calendar days of the notice of invalidation pursuant to section 95985(e)(2), each outstanding ARB offset credit will constitute a violation pursuant to section 96014. If ~~the~~ any party identified in section 95985(c) is no longer in business ARB will require those who are still in business, whether the Authorized Project Operator, the Authorized Project Designee and/or the verifier(s) to provide the full amount of the replacement within said 90 days and each outstanding ARB offset credit following that 90 days will constitute a violation of section 96014. ~~the Offset Project Operator or Authorized Project Designee to replace each invalidated ARB offset credit and will notify the Offset Project Operator or Authorized Project Designee that they must replace them. The Offset Project~~

~~Operator or Authorized Project Designee must replace each metric ton of CO2e with a valid ARB offset credit or another approved compliance instrument pursuant to subarticle 4 within 90 days of notification by ARB pursuant to 95985(e)(3). If the Authorized Project Operator or Authorized Project Designee does not replace each invalid ARB offset credit within 90 calendar days of notification by ARB pursuant to section 95985(c)(3), each outstanding ARB offset credit will constitute a violation pursuant to section 96014.~~ (GREENX)

Comment: Further revise the offset liability to expand the Forest Buffer Account concept to all offset credits and amend the invalidation period to expire when ARB accepts a second verification. As proposed, the liability for offset credits that have been issued but later invalidated by ARB is placed on the buyer of the credit. Shell believes the risks associated with such invalidation and penalties will inhibit the development of the offsets market and the innovations and pioneering GHG technologies that offsets can drive. We appreciate ARB's efforts to establish criteria and limitations to the invalidation process and to promote development of insurance products. However, we believe more is necessary to address this issue. Shell supports and recommends the following two amendments proposed by IETA:

- Expand the Forest Buffer Account concept to create a compliance buffer account for all offset credits. ARB has a precedent for administering a compliance buffer account with the Forest Buffer Account. Credits subject to an unintentional reversal will remain valid, and ARB will retire credits from the Forest Buffer Account. A similar thought process is behind IETA's proposed compliance buffer account, where invalid offsets will remain in circulation, but the system will be made whole through the retirement of offsets from the compliance buffer account. The proposal also allows ARB to pursue the responsible party in instances of egregious error or fraud to prevent issues of moral hazard. This is a fair and workable model.
- Allow the invalidation period of expire upon the date of ARB's acceptance of the second verification. As proposed, the Regulation includes an eight year statute of limitations for the invalidation of offsets that may be reduced to five years, if a project undergoes a second verification within 3 years of issuance of credits. We believe the invalidation period should be lifted as soon as the second verification is accepted by ARB. (SHELLOIL)

Comment: CCEEB is concerned that the risks associated with invalidation of approved offset credits will inhibit the development of the offset market. We appreciate the changes that ARB has made in establishing criteria and limitations to the invalidation process. However more must be done. CCEEB supports the IETA proposal and recommends that ARB should expand the Forest Buffer Account concept to create a compliance buffer account for all offset credits and allow the invalidation period to expire upon ARB's acceptance of the second verification. (CCEEB3)

Comment: If ARB retains the concept of invalidating issued offset credits, we suggest removing the buyer liability terms and put the onus squarely on the entities that put the credit into the compliance market. Focusing on those who create and verify the credit will enhance the offset market and provide additional comfort to the market as to the quality of offsets thereby promoting a more liquid market. In addition to, or as an alternative, ARB could provide an exemption step for the Offset Project Operator and/or the Authorized Project Designee so either (or the verifier) can choose to avoid the sanctions threatened by 95985 and risk of liability years after the offset credit was created. We suggest that any project which has had a second verifier review the project, such as the requirements proposed in section 95977.1 for rotation to a new verifier, should be exempt from the threat of invalidation. We believe this is an unnecessary extra cost for projects, but it is far better than putting the market at risk because of the vague and uncertain threat of proposed section 95985. This is a concept similar to that suggested by IETA. In lieu of this exemption or "safe harbor" concept, we also would support the buffer pool concept as proposed by IETA. Modify sections 95985(c) and (f) as follows:

> (c) If ARB determines that an ARB offset credit is invalid pursuant to section 95985(b) ARB will identify the Offset Project Operator, the Authorized Project Designee and the verifier(s) of the offset credit in question, the current holder of the ARB offset credit or the entity that submitted the ARB offset credit for compliance or retirement.
>
> > (~~1) Identify the current holder of an ARB offset credit that has not been transferred to a compliance account or submitted for retirement;~~
> > ~~(2) Identify the entity that holds an ARB offset credit in its compliance account or has submitted it for compliance or retirement; and~~
> > ~~(3) The Offset Project Operator and Authorized Project Designee, and Forest Owner, if applicable.~~
>
> (f) Requirements for Non-Sequestration Offset Projects. If an ARB offset credit is found to be invalid pursuant to sections 95985(b) and (d). the part~~y~~ies identified in section 95985(c) must replace each metric ton of CO_2e with a valid ARB offset credit or another approved compliance instrument pursuant to subarticle 1 within 90 calendar days of the notice of invalidation pursuant to section 95985(e)(2), each outstanding ARB offset credit will constitute a violation pursuant to section 96014. If ~~the~~ any party identified in section 95985(c) is no longer in business ARB will require those who are still in business, whether the Authorized Project Operator, the Authorized Project Designee and/or the verifier(s) to provide the full amount of the replacement within said 90 days and each outstanding ARB offset credit following that 90 days will constitute a violation of section 96014. ~~the Offset Project Operator or Authorized Project Designee to replace each invalidated ARB offset credit and will notify the Offset Project Operator or Authorized Project Designee that they must replace them. The Offset Project Operator or Authorized Project Designee must replace each metric ton of C02e with a valid ARB offset credit or another approved compliance instrument pursuant to subarticle 4 within 90 days of notification by ARB pursuant to 95985(e)(3) If the Authorized Project Operator or Authorized Project Designee does not replace each invalid ARB offset credit within 90 calendar days of~~

~~notification by ARB pursuant to section 95985(c)(3), each outstanding ARB offset credit will constitute a violation pursuant to section 96014~~. (GREENX)

Response: We do not agree that we should eliminate buyer liability associated with the invalidation of ARB offset credits. Requiring the user to replace the invalidated offsets ensures that purchasers and users of offset credits do their due diligence in seeking out high-quality offset credits. We have clear enforcement authority over covered entities that will be using ARB offsets for compliance. If the covered entity replaces any invalidated offset credits, they may then take appropriate action through third-party contractual arrangements that they may have established prior to purchase. These arrangements currently exist in the voluntary offset market, and we expect that as the offset market becomes more established, that additional mechanisms to deal with the risk of invalidation will also be established. In the event that the offset credit has not yet been used or retired, it will be canceled in the market tracking system and removed from any Holding or Compliance Accounts. These provisions in no way diminish our authority to assess penalties under section 96014 on any offset project developer or verifier that has provided false information to ARB.

We do not agree that ARB offset credits should no longer be invalidated in the event that a second verification is performed on the Offset Project Data Report. The minimum statute of limitations is three years if the Offset Project Data Report or a subsequent Offset Project Data Report, depending on project type, is verified by a different verifier within that time frame. If the offset project does not qualify under these requirements, the default statute of limitations is eight years. We do not believe that any time period less than three years would provide sufficient time to detect all relevant new information or uncover any mistakes that verifiers may have missed or may have been unintentionally omitted.

M-101. (multiple comments)
Comment: Assigning liability for replacement of invalidated offset credits to the buyer or any entity within the supply chain (section 95985) would drive market participants to attempt to create chains of indemnity. Most Forest Owners would require that any companies or individuals involved in project development not only indemnify the forest owner for professional errors, but also carry insurance. In the absence of a proper insurance product, most potential offset producers would elect to not participate in the market because the relative risk of liability. We therefore suggest that ARB reconsider the alternative mechanism of addressing valid concerns over material mistakes or fraud in offset production: an ex-ante deduction and buffer reserve. The mechanics of operating a buffer account do not differ at all between different types of buffer accounts. Only the root cause of credit invalidation varies. ARB has the option of simply setting the deduction at a very conservative rate and applying adaptive management as data comes in. If the ex-ante deduction was too high and very few credits are being invalidated, ARB could reduce the deduction in future vintage years. If the ex-ante deduction was too low and more credits were invalidated than were retained by the

buffer reserve, ARB could increase the deduction in future vintage years and ensure climate integrity by reducing the cap by an appropriate amount. (NEWFOREST2)

Comment: EDF is very concerned by the portion of the draft regulation which imposes front-line responsibility for credit reversal and invalidation on the purchasers of credits, (i.e. buyer liability). While EDF does support the requirement that any credit which is determined to be invalid, either through reversal or invalidation, is replaced with a certified emission reduction credit, the current approach to make buyers responsible for making up the credit is likely to suppress the overall market without furthering environmental integrity when compared to alternative designs. Buyer liability makes offsets non-homogenous, which will hurt the liquidity of the market. Financial entities will likely provide credit replacement insurance products, but because the market cannot calculate the risk that ARB will invalidate a credit, this insurance will be expensive and inefficient. The cost of the insurance will increase the costs of offsets, thereby increasing costs of emission reductions for the entire program, and for Californians. Because smaller projects will likely be the most expensive to insure, buyer liability will also discourage the types of offset projects which often have the greatest environmental co-benefits for California communities. We recommend CARB consider other frameworks that have been suggested that will guarantee the environmental integrity of offsets without these unnecessary costs and without threatening the viability of the market. CARB could require 1.05 tons of offset credits to be surrendered for every ton of compliance obligation, with the extra 5 percent placed in an account that is available for surrender if offset credits are later reversed. As the risk of reversal for offsets became clearer, or the size of the account grew or shrunk, the percentage of additional offsets that CARB required covered entities to submit could be adjusted. This approach ensures market integrity while also removing potential barriers to credit development. (EDF4)

Comment: Liability for Offset Rescission – Cost containment provided by a robust offset supply is a critical element of the December 2010 rule. The liability regime for offset rescission included in the proposal, however, will jeopardize this supply because it will significantly discourage investment in and financing of offset projects. The offset rescission risk is difficult to manage on a transaction-by-transaction basis—based on experience, no private insurance product is available or likely to be available to address it—but the risk can easily be borne by the market as a whole at a marginal cost to each market participant. Overall this risk is best managed by the creation of a buffer pool on a program-wide basis, with the ultimate risk residing with the program itself. If ARB does not believe that this option is practical or feasible, ARB should consider the alternative of removing a quantity of allowances from the cap equal to the number of offsets rescinded, for which recovery from a culpable party is not possible. Chevron would generally oppose removing any allowances from the cap. However, faced with the prospect of inadequate offset supply and higher allowance prices in the market, Chevron would rather have ARB implement this alternative solution than leave the current proposal in place. (CHEVRON3)

Comment: Requiring regulated entities to replace invalidated credits will unnecessarily restrict the supply of high quality offsets without real net environmental gains. The problem lies in the assumed benefits of this system. Buyers (regulated entities) are assumed to be protected from receiving bad credits through use of insurance mechanisms, trained offset verifiers, innovative contracting, and extensive due diligence. It is also assumed that ARB is more likely to recover an invalidated offset credit if a regulated entity is held liable for its replacement. However, no private carbon offset insurance products currently exist; the private sector cannot mandate that all projects and offset holders purchase a common insurance policy or participate in a common buffer account; any voluntary insurance policy or buffer account would suffer from "adverse selection" as project developers and sellers would be incentivized to submit only their riskiest projects to the voluntary insurance policy or buffer account, and they would sell the least risky projects directly to large compliance entities via bilateral contract; transparency will be sacrificed and market oversight will be more difficult; and smaller compliance entities would not have equal access to quality offsets. The solution to addressing the problems associated with holding regulated entities responsible for replacing an invalidated offset credit is to mirror the current ARB Forest Buffer Account structure and procedures to apply separately (and additionally) to all compliance offset projects. This system would reduce transaction costs while maintaining environmental integrity in the overall Cap and Trade system. This system would also align the incentives of Offset Project Operators, verifiers, buyers, sellers, and regulated entities, as well as result in a fungible, commoditized offset market which is equitable, accessible by all compliance entities, and would allow transparent trading and clearing via exchange. It would merely be an extension of the buffer account management and enforcement action responsibilities already undertaken by ARB for forestry projects, and will reduce invalidation risk because the incentives of Offset Project Operators will be properly aligned to ensure the quality of their projects. (CE2CC)

> **Response:** We do not agree that we should eliminate buyer liability associated with the invalidation of ARB offset credits. Requiring the user to replace the invalidated offsets ensures that purchasers and users of offset credits do their due diligence in seeking out high-quality offset credits. We have clear enforcement authority over covered entities that will be using ARB offsets for compliance. If the covered entity replaces any invalidated offset credits, they may then take appropriate action through third-party contractual arrangements that they may have established prior to purchase. These arrangements currently exist in the voluntary offset market, and we expect that as the offset market becomes more established, that additional mechanisms to deal with the risk of invalidation will also be established. In the event that the offset credit has not yet been used or retired, it will be canceled in the market tracking system and removed from any Holding or Compliance Accounts. These provisions in no way diminish our authority to assess penalties under section 96014 on any offset project developer or verifier that has provided false information to ARB.

With regard to the comments related to the development of insurance, we believe that given all of the clarifications to section 95985, the market should be able to quantify and cover the risk associated with invalidation. We expect that insurance products will emerge once the market has been established.

With regard to the suggestion to hold allowances to replace invalidated offsets, this suggestion would most likely face serious opposition from other covered entities, as it would reduce the amount of compliance instruments available in the market and would take the incentive off buyers to conduct due diligence in reviewing and selecting offsets for purchase and compliance purposes.

M-102. Comment: ACR believes that significant problems remain in section 95985. In the case that ARB is relying on the assumption that commercially available insurance will cover invalidation risk, five years may still be too long a horizon for insurance underwriters since there is no history on which to determine probability of occurrence of invalidations. It is a challenge even for experienced insurers to take on risk beyond three years, particularly in a new market. More broadly, the fact that replacement liability remains with the current holder of the ARB offset credit will likely pose obstacles to the development of a smoothly functioning offset market. ACR has not seen evidence that insurance products covering invalidation risk are commercially available or can necessarily be assumed to become available in the near-term. Even if insurance products are offered in the future, whether these will cover invalidation, will be available at competitive prices, and will adequately protect the market remains to be seen. Thus we feel that assigning replacement liability to the current holder of the credit or the entity that submitted the credit for compliance or retirement is fundamentally problematic. A "seller liability" approach, in which the replacement responsibility rests with the Offset Project Operator or Authorized Project Designee in the case of invalidation, more appropriately aligns the liability for invalidation with those who have the sectoral knowledge and ability to minimize the risk of invalidation. This would in effect require the sellers to stand by their product and to offer buyers some form of warranty that product is guaranteed valid until the offset is used for compliance or retired. ACR believes that market-based risk mitigation solutions are possible, either offered directly to Offset Project Operators or Authorized Project Designees, or offered via the Offset Project Registries, to cover invalidation risk. We will work with ARB to identify such solutions. (MARTINN3)

Response: We do not agree that the responsible party of an invalidated ARB offset credit should be the offset developer. We have clear enforcement authority over covered entities that will be using ARB offsets for compliance. If the covered entity replaces any invalidated offset credits, they may then take appropriate action through third-party contractual arrangements that they may have established prior to purchase. These arrangements currently exist in the voluntary offset market, and we expect that as the offset market becomes more established, that additional mechanisms to deal with the risk of invalidation will also be established. In the event that the offset credit has not yet been used or retired, it will be canceled in the market tracking system and removed from any

Holding or Compliance Accounts. Requiring the user to replace the invalidated offsets ensures that purchasers and users of offset credits do their due diligence in seeking out high-quality offset credits.

With regard to the comments related to the development of insurance, we believe that given all of the clarifications to section 95985 the market should be able to quantify and cover the risk associated with invalidation. We expect that insurance products will emerge once the market has been established.

M-103. Comment: ARB believes that a market of insurance products will be created to address the risk of invalidation. An insurance product in California would need to cover a post-delivery risk that does not exist in any other market. According to insurance companies and brokers, this risk cannot be easily quantified. Because of the quantification risk, only the largest projects would be able to obtain such insurance. Smaller offset projects, such as manure digesters, will either not develop, or will be very expensive to develop. Some have asserted that complying entities can manage their liability risk through contractual language. The primary remedies a complying entity may seek are inclusion of liquidated damages and indemnification clauses in their contracts with sellers of offsets. In our investigation, PG&E has learned that at least one of the largest developers of offsets would not sign such contracts. Even if the offset seller was willing to accept such contractual language, the seller would need to remain solvent or post significant amounts of collateral with PG&E for the entire invalidation period in order to limit PG&E's liability. Even if they are willing to post, offset sellers are likely to build the cost of collateral and additional risk into the cost of the offset, which will shift the cost to PG&E and other offset purchasers. Because only the largest projects would be able to meet such collateral requirements, the available supply of offsets would be even more restricted than predicted. If a buyer liability approach cannot be avoided, PG&E supports two potential approaches to address the potential risk of invalidation. The first is the development of a Compliance Buffer Account funded through the hold back of a percentage of credits from every offset project. This account could be managed by the ARB as the Forest Buffer Account or be managed separately by a third party. Under this proposal, the market itself bears the risk of invalidated credits. Rather than requiring each buyer to manage this risk on a project-by-project basis, this proposal effectively has the entire market taxing itself—by taking issued credits out of the market—in order to create a buffer account that ensures the environmental integrity of the program. ARB staff has posed the question about what would happen should the Compliance Buffer Account become depleted. This could be addressed by increasing the percent held back from a project if more than 50 percent of the offsets are withdrawn from the Compliance Buffer Account. The second approach would be a "double verification" of all projects. This is similar to section 95985(b)(6), which allows the reduction of the statute of limitation from eight to five years "if an offset project is verified after three years of ARB offset credit issuance." PG&E recommends that ARB simply allow the invalidation period to expire upon the date of ARB's acceptance of the second verification. We see no reason to require that a second verification "sit" for five years before lifting the shadow of invalidation. Nothing is gained from the passage of time, and the marketplace will not consider the credit valid and marketable for the length of that period. (PGE4)

> **Response:** We do not agree that ARB offset credits should no longer be invalidated in the event that a second verification is performed on the Offset Project Data Report. The minimum statute of limitations is three years if the Offset Project Data Report or a subsequent Offset Project Data Report, depending on project type, is verified by a different verifier within that time frame. If the offset project does not qualify under these requirements, the default statute of limitations is eight years. We do not believe that any time period less than three years would provide sufficient time to detect all relevant new information or uncover any mistakes that verifiers may have missed or may have been unintentionally omitted.
>
> With regard to the comments related to the development of insurance, we believe that given all of the clarifications to section 95985 the market should be able to quantify and cover the risk associated with invalidation. We expect that insurance products will emerge once the market has been established.

M-104. (multiple comments)
Comment: PG&E appreciates the development of an eight year statute of limitations for an offset project and the reduction of the eight year statute of limitations to five years if an offset project is verified after three years of ARB offset credit issuance. PG&E recommends the addition of a double verification option prior to offset credit issuance. (PGE4)

Comment: We urge ARB simply to allow the invalidation period to expire upon the date of ARB's acceptance of the second verification. We see no reason to require that a second verification "sit" for five years before lifting the shadow of invalidation. Nothing is gained from the passage of time—and yet, the marketplace will not consider the credit valid and marketable for the length of that period. (CERP4)

Comment: The current language on the Statute of Limitations on offset invalidation in section 95985(b)(6) allows for the potential to reduce the Statue of Limitations on offset invalidation from eight years to five if the project is verified by a different verifier after three years, versus the requisite six years. The Regulation should include additional options to eliminate the Statute of Limitations if the Offset Project Operator or Early Action offset holder elects to use two different verifiers at the time of verification for Compliance projects or regulatory re-verification (i.e. desk review) for Early Action offsets; and allow the Statute of Limitations to be reduced to two years if a project voluntarily uses a different verifier after one year. These options allow more flexibility and would continue, to, "encourage a quicker verifier rotation so that any issues that may occur may be uncovered sooner, further enhancing the integrity of the offset program." (CE2CC)

Comment: In the current proposal, ARB has added a statute of limitations of eight years for invalidation of already-issued offset credits. In addition, it appears that a project can shorten the statute of limitations to five years if it undergoes a second verification after three years of issuance of the credits. According to this yardstick of credibility, ARB considers the validity of offset credits sufficiently established after the project has been reviewed by a second, independent ARB-accredited verifier and the second verifier has not identified any grounds for validation as set forth in section 95985(b). IETA believes this is a well-grounded approach. Also, it provides a basis for minimizing the most problematic aspect of buyer liability: the extended period of time during which an already-issued offset credit remains subject to invalidation. In particular, we think it would lead many entities in the offsets market to manage their risk by obtaining a second verification of each data report immediately following the issuance of credits, which would bolster the credibility of the program. A long statute of limitations would also severely impact the ability to access insurance products. IETA urges ARB simply to allow the invalidation period to expire upon the date of ARB's acceptance of the second verification. We see no reason to require that a second verification "sit" for five years before lifting the shadow of invalidation. Nothing is gained from the passage of time, and the marketplace will not consider the credit valid and marketable for the length of that period. (IETA3)

Comment: Section 95985(b)(6) provides that if an offset is certified by two different verifiers (after three years), then ARB may invalidate the offset within five years of issuance rather than the usual eight years. SCE supports this move toward limiting offset invalidation as this will create more market confidence and has the potential to lower compliance costs. However, SCE strongly recommends that ARB further adjust its provisions to increase confidence in the offset markets while maintaining the environmental integrity of the fully verified offsets. Modify section 95985(b)(6) as follows:

> (6) If an offset project is verified ~~after three years of~~ <u>at any time after</u> ARB offset credit issuance by a different offset verifier, ARB may <u>no longer</u> invalidate ~~within five years of issuance of~~ the ARB offset credits covered by an Offset Project Data Report. (SCE3)
>
> **Response:** We do not agree that ARB offset credits should no longer be invalidated in the event that a second verification is performed on the Offset Project Data Report. The minimum statute of limitations is three years if the Offset Project Data Report or a subsequent Offset Project Data Report, depending on project type, is verified by a different verifier within that time frame. If the offset project does not qualify under these requirements, the default statute of limitations is eight years. We do not believe that any time period less than three years would provide sufficient time to detect all relevant new information or uncover any mistakes that verifiers may have missed or may have been unintentionally omitted.

M-105. (multiple comments)
Comment: The process for invalidation of credits should be carefully constructed with a limited horizon. The Trust recommends that ARB limit the time frame for invalidation

of credits to the earlier of the eight year statute of limitations, or the second verification of credits, whichever comes first. ARB considers the validity of credits to be convincingly established after five years if a second verifier has not identified any grounds for invalidation as set forth in section 95985(b)(6). The Trust believes there is no reason to wait five years; ARB should accept a second verification as the final point for any potential invalidation.

In addition, The Trust urges ARB to modify the provisions under which offset credits may be invalidated. Modify section 95985(b) as follows:

- ~~Information that is not "true, accurate, or complete" (section 95985(b)(1)).~~
- Documentation that contains errors whereby emission reductions are overstated by 5% or more (section 95985(b)(2)).
- The project did not meet applicable legal requirements (section 95985(b)(3)).
- The credits have been issued in another program (section 95985(b)(4)).

In the Trust's experience, it is foreseeable that some projects will have documentation with unintended inaccuracies or omissions. Furthermore, under the rule as written, it appears ARB could invalidate all of the credits from the project rather than just the credits affected by the inaccuracies. This is an overly broad and punitive solution. ARB should limit the liability from "overstatement" to the extent of the overage. (TCT)

Comment: The criteria which determines whether CARB can or will invalidate an offset is too broad. Invalidation should occur only when there is a material misstatement or inaccuracy in the information submitted to CARB or to verifiers. "Material" should be defined as a misstatement or inaccuracy that overstates the amount of GHG reduction by more than 5 percent. The Regulation considers that offsets could be verified twice and thereafter reduce the statute of limitations on invalidation to five years. We believe a second verification should result in a reduction in the statute of limitations of one year. (BP2)

> **Response:** We included extensive modified provisions in section 95985 to make it clear what would trigger an invalidation, how ARB will invalidate offsets, and which offsets will need to be replaced. We believe that these changes provide clarity on these points.
>
> Section 95985(b) was modified to establish a statute of limitations for the invalidation of ARB offset credits of three years if the Offset Project Data Report or a subsequent Offset Project Data Report, depending on project type, is verified by a different verifier within that time frame. If the offset project does not qualify under these requirements, the default statute of limitations is eight years. We believe that the three-year time period is sufficient to uncover any new information, as long as the project has been reviewed by a second verifier. If it is not looked at by a second verifier, we believe that eight years is necessary to uncover any new information that could lead to the invalidation of ARB offset credits. We believe the eight-year statute of limitations is sufficient because it

would allow two verification parties to examine the offset credits in question for continuous projects.

We do not agree that ARB offset credits should no longer be invalidated in the event that a second verification is performed on the Offset Project Data Report. The minimum statute of limitations is three years if the Offset Project Data Report or a subsequent Offset Project Data Report, depending on project type, is verified by a different verifier within that time frame. If the offset project does not qualify under these requirements, the default statute of limitations is eight years. We do not believe that any time period less than three years would provide sufficient time to detect all relevant new information or uncover any mistakes that verifiers may have missed or may have been unintentionally omitted.

M-106. Comment: Specific modifications should be made to the invalidation rules to improve fairness and efficiency. We urge ARB to consider the further modifications outlined below.

Modify the "Statute of Limitations." ARB has proposed to shorten the period of time during which an offset credit is subject to invalidation from eight years to five. See Section 95985(a). We urge ARB simply to allow the invalidation period to expire upon the date of ARB's acceptance of the second verification, regardless of when that occurs. It is that second verification that will provide the final measure of assurance regarding the credit's validity. There is not need to require a credit be subject to a further arbitrary period of five years during it which would be subject to invalidation—and thus unmarketable.

Modify the Conditions for Invalidating Credits. We appreciate ARB's proposal to modify section 95985(b) to specify the conditions under which offset credits may be invalidated. As now proposed, subsections 95985(b)(1)-(4) establish four conditions under which offset credits may be invalidated: (1) the project information is not "true, accurate, or complete"; (2) the project documentation contains errors such that emission reductions achieved by the project are overstated by 5% or more; (3) the project did not meet all applicable legal requirements; and (4) a finding that credits already have been issued for the project in another program.

Eliminate the Catch-All Condition. We respectfully suggest that ARB eliminate subsection 95985(b)(1). Given the myriad requirements of the offset regulations, any number of projects will have documentation that has inadvertent inaccuracies or omissions. Yet, under this new provision, a minor paperwork problem could result in invalidation of 100% of the offset credits already issued for a project—even if there was no impact on the reductions or removals actually achieve by the project. Any discrepancies that do have material effects on the environmental integrity of the project are addressed by subsections (b)(2), (3), and (4).

> Tailor the "Overstatement" Condition to the Actual Invalidity. We respectfully suggest that ARB modify subsection 95985(b)(2) relating to "overstatement" to tailor it to those credits actually impacted by the overstatement. In the event that an offset data report overstates emission reductions achieved by a project, ARB should invalidate only an amount of credits that corresponds to the overstatement. As currently proposed, ARB would invalidate *all* credits associated with the report, even the credits that correspond to real emission reductions. (COPC3)

Response: Section 95985(b) was modified to establish a statute of limitations for the invalidation of ARB offset credits of three years if the Offset Project Data Report or a subsequent Offset Project Data Report, depending on project type, is verified by a different verifier within that time frame. If the offset project does not qualify under these requirements, the default statute of limitations is eight years. We believe that the three-year time period is sufficient to uncover any new information, as long as the project has been reviewed by a second verifier. If it is not looked at by a second verifier, we believe that eight years is necessary to uncover any new information that could lead to the invalidation of ARB offset credits. We believe the eight-year statute of limitations is sufficient because it would allow two verification parties to examine the offset credits in question for continuous projects.

We included extensive modified provisions in section 95985 to make it clear what would trigger an invalidation, how we will invalidate offsets, and which offsets will need to be replaced. We believe that these changes provide clarity on this point.

M-107. Comment: In the Proposed Changes, ARB added a provision under which the period of time during which the offset credit is subject to invalidation can be shortened from eight years to five years. This period should simply expire upon the earlier of the date of the ARB's acceptance of the second verification, or five years after issuance. There is no reason to require that a second verification "sit" for a certain period of time before lifting the shadow of invalidation. Nothing is gained from the passage of time—and yet, the marketplace will not consider the credit valid and marketable for the length of that period.

Second, the ARB should modify the list of potential issues with offset credits. SCPPA respectfully requests the ARB to eliminate section 95985(b)(1): the project information is not "true, accurate, or complete." Given the myriad requirements of the offset regulations, any number of projects will have documentation that has inadvertent inaccuracies or omissions. Yet, under this vague and overbroad provision, a minor paperwork problem could result in invalidation of 100 percent of the offset credits already issued for a project—even if there was no impact on the reductions or removals actually achieved by the project. This is a draconian, "gotcha" approach that will deter development of offset projects for reasons unrelated related to environmental integrity. Furthermore, any discrepancies that do have material effects on the environmental integrity of the project are completely addressed by sections 95985(b)(2), (3), and (4). For these reasons, SCPPA respectfully urges the ARB to delete section 95985(b)(1). Third, the provision related to "overstatement" (section 95985(b)(2)) should be modified to avoid unnecessarily punitive outcomes. If an offset data report overstates emission reductions achieved by a project, the ARB should require additional offsets to be surrendered in an amount that corresponds to the overstatement. As currently proposed, the ARB would invalidate all offset credits associated with the report, even the portion of the offset credits that correspond to real emission reductions. If the ARB continues to rely on a buyer liability approach, it could apply the more limited invalidation pro rata to all holders of offset credits from the particular vintage year. Finally, 90 days remains a very tight timetable for any entity to obtain additional compliance instruments. SCPPA respectfully urges the ARB to align this provision with the provision on under-reporting of emissions, which allows six months to surrender additional compliance instruments (section 95858(c)). For the reasons discussed above, section 95985 should be revised as follows, to implement the buffer approach, remove references to invalidation, and refine the grounds for finding that problems have arisen in relation to issued offset credits. Modify section 95985 as follows:

Section 95985. Surrender of additional~~Invalidation of~~ ARB Offset Credits if circumstances arise in relation to existing ARB Offset Credits.

(a) An ARB offset credit issued under this Article will remain valid provided that, if ARB makes a determination pursuant to section 95985(e)(4) then an additional compliance instrument must be surrendered in accordance with sections 95985(f) and (g). ~~unless invalidated pursuant to sections 95985(b) and (c)~~.

(b) ARB may determine at any time until the earlier of (i) a post-issuance verification of the Offset Project Data Report by a different offset verifier, and (ii)~~within~~ 5~~8~~ years after~~of~~ issuance, ~~except as provided in section 95985(b)(5) and (6),~~ that ~~an ARB offset credit is invalid for the following reasons~~:

~~(1) ARB determines that information provided to ARB for an Offset Project Data Report or Offset Verification Statement by offset verifiers, verification bodies, Offset Project Operators, Authorized Project Designees, or Offset Project Registries, related to an offset project was not true, accurate, or complete; or~~

(~~2~~1) The Offset Project Data Report contains errors that overstate the amount of GHG reductions or GHG removal enhancements by more than 5 percent (in which case, ARB shall determine the amount of offset credits that corresponds to the overstatement); or

(~~3~~2) The offset project did not meet all local, state, or national regulatory requirements during the time covered by an Offset Project Data Report; or

(~~4~~3) ~~ARB determines that o~~Offset credits have been issued in any other voluntary or mandatory program within the same offset project boundary or for the same GHG reductions or GHG removal enhancements covered by an Offset Project Data Report.

~~(5) If an offset project is developed under Compliance Offset Protocol U.S. Ozone Depleting Substances Projects, ARB may invalidate within five years of issuance of the ARB offset credits covered by an Offset Project Data Report.~~

~~(6) If an offset project is verified after three years of ARB offset credit issuance by a different offset verifier, ARB may invalidate within five years of issuance of the ARB offset credits covered by an Offset Project Data Report.~~

(~~7~~c) An update to a Compliance Offset Protocol in itself, will not result in an invalidation of ARB offset credits issued under a previous version of the Compliance Offset Protocol.

(~~c~~d) If ARB makes a determination pursuant to section 95985(b), then ~~determines that an ARB offset credit is invalid pursuant to section 95985(b)~~ ARB will identify all parties that may have some responsibility for the action that gave rise to the determination. Such parties may include:

> (1) ~~Identify~~ the current holder of an ARB offset credit that has not been transferred to a compliance account or submitted for retirement;
>
> (2) ~~Identify~~ the entity that holds an ARB offset credit in its compliance account or has submitted it for compliance or retirement; and
>
> (3) The Offset Project Operator and Authorized Project Designee, and, if applicable, the Forest Owner~~, if applicable~~.

(~~d~~e) ARB will notify the parties identified in section 95985(~~c~~d) of the determination pursuant to section 95985(b)~~invalidation~~ and provide ~~the~~each party an opportunity to submit additional information to ARB ~~prior to invalidation~~ as follows:

> (1) ARB will include the reason for finding that the issue listed in section 95985(b) occurred~~invalidation of an ARB offset credit~~ in its notification to the party identified in 95985(d~~c~~).
>
> (2) After notification the part~~y~~ies identified in 95985(d~~c~~) will have 25 calendar days to provide any additional information to ARB.

(3) ARB may request any additional information as needed in addition to the information provided under this section.

(4) The Executive Officer will have 30 days after all information is submitted under this section to make a final determination that one of the conditions listed in section 95985(b) has occurred, to identify and notify the party responsible, and to determine the number of offset credits affected and the compliance instruments that are required to be surrendered~~to invalidate an ARB offset credit~~.

~~(e) If the Executive Officer determines that an ARB offset credit is invalid pursuant to sections 95985(b) and (d):~~

~~(1) The ARB offset credit will be invalidated and removed from any Holding or Compliance Account;~~

~~(2) The party identified pursuant to section 95985(c) will be notified of ARB's determination of invalidation pursuant to section 95985(d)(4);~~

~~(3) The Offset Project Operator or Authorized Project Designee, or the Forest Owner, if applicable, of the offset project for which the ARB offset credits were invalidated will be notified of ARB's determination of invalidation pursuant to section 95985(d); and~~

~~(4) Any approved program for linkage pursuant to subarticle 12 will be notified of the invalidation at the time of ARB's determination pursuant to section 95985(d)(4).~~

(f) Requirements for Surrender of Additional Compliance Instruments~~Non-Sequestration Offset Projects~~. If the Executive Officer makes a determination~~an ARB offset credit is found to be invalid~~ pursuant to section~~s~~ 95985(e)(4)~~b) and (d)~~, the party identified in section 95985(e)(4)~~c)(2)~~ must surrender the specified number of ~~replace each ARB offset credit with a~~ valid ARB offset credits or ~~an~~other approved compliance instruments pursuant to subarticle 4, within ~~90 calendar days~~six months of notification by ARB pursuant to section 95985(e).

(g) If the party identified in section 95985(e~~c~~)(~~2~~4) does not surrender the specified number of compliance instruments~~replace each invalid ARB offset credit~~ within ~~90 calendar days~~six months of the notice ~~of invalidation~~ pursuant to section 95985(e):~~,~~

(1) ARB will retire the specified number of ARB offset credits from the Offset Buffer Account; and

(2) the party will be subject to enforcement action pursuant to section 96014; and

(3) each ~~outstanding~~ ARB offset credit retired from the Offset Buffer Account will constitute a violation pursuant to section 96014. ~~If the party identified in section 95985(c)(2) is no longer in business ARB will require the Offset Project Operator or Authorized Project Designee to replace each invalidated ARB offset credit and will notify the Offset Project Operator or Authorized Project Designee that they must replace them. The Offset Project Operator or Authorized Project Designee must replace each ARB offset credit with a valid ARB offset credit or another approved compliance instrument pursuant to subarticle 4, within 90 calendar days of notification by ARB pursuant to section 95985(e). If the Offset Project Operator or Authorized Project Designee does not replace each invalid ARB offset credit within 90 calendar days of notification by ARB pursuant to section 95985(e), each outstanding ARB offset credit will constitute a violation pursuant to section 96014.~~

~~(g) Requirements for Forest Offset Projects. If an ARB offset credit is found to be invalid pursuant to sections 95985(b) and (d) for a forest offset project, the Forest Owner must replace each ARB offset credit with a valid ARB offset credit or another approved compliance instrument pursuant to subarticle 4, within 90 calendar days of notification by ARB pursuant to section 95985(e). If the Forest Owner does not replace the invalid ARB offset credit within 90 calendar days of being notified by ARB pursuant to section 95985(e), each outstanding ARB offset credit will constitute a violation pursuant to section 96014.~~

(h) Nothing in this section shall limit the authority of the State of California from pursuing enforcement action against any parties in violation of this article. (SCPPA6)

Response: Section 95985(b) was modified to establish a statute of limitations for the invalidation of ARB offset credits of three years if the Offset Project Data Report or a subsequent Offset Project Data Report, depending on project type, is verified by a different verifier within that time frame. If the offset project does not qualify under these requirements, the default statute of limitations is eight years. We believe that the three-year time period is sufficient to uncover any new information, as long as the project has been reviewed by a second verifier. If it is not looked at by a second verifier, we believe that eight years is necessary to uncover any new information that could lead to the invalidation of ARB offset credits. We believe the eight-year statute of limitations is sufficient because it would allow two verification parties to examine the offset credits in question for continuous projects.

We included extensive modified provisions in section 95985 to make it clear what would trigger an invalidation, how we will invalidate offsets, and which offsets will need to be replaced. We believe that these changes provide clarity on this point.

We changed the timing for when the responsible party must replace the invalidated ARB offsets from 30 days to six months. This should provide enough flexibility for those that must replace invalidated offsets to purchase additional compliance instruments while still ensuing that the environmental integrity of the cap is maintained.

M-108. (multiple comments)
Comment: Economically viable insurance products will not emerge to manage buyer liability. Some ARB officials see insurers coming to the rescue. For several reasons, IETA is skeptical about the emergence of viable insurance products. Insurers typically assess and insure against risks that apply to private activities or enterprises. In an offsets market, by contrast, the risk relates to the performance of a government program, and the ARB offsets system is a government program with no track record of experience. Cost-effective insurance for individual projects/trades are very unlikely to materialize in such a small and idiosyncratic market, particularly in the early stages. In other types of more mature and "natural" markets, the cost of insurance can come down if offered on the basis of large pools. However, there is no mechanism in the offset Regulations that makes such pooling possible for private insurers unless ARB was to purchase insurance on behalf of the market to cover all trades. Still, insurers would always require a deductible and there are the issues as to how to price it based on no direct experience initially. As a result, any insurers for ARB offsets market would have to build up such pools on their own over time with resulting higher costs. These costs will be passed through to covered entities in their rates. (IETA3)

Comment: Some ARB officials have said they see insurance products emerging to fill the gap—and say that some insurance companies already have come to the agency with a "build it and we will come" message. Based on what we have learned about conversations with insurance companies about the California offsets program and our experience with insurance in other markets, we are much more skeptical. We have concluded that, for the following reasons, economically viable insurance products are not likely to emerge under a buyer liability regime.

First, insurers generally are confounded by the area of government-issued offsets. Insurers typically assess and insure against risks that apply to activities or enterprises. In an offsets market, by contrast, the relevant risk relates to the performance of a government program—and, in the case of the ARB offsets system, a government program with no track record of experience. Like most buyers of credits, insurers have no particular insight into the risk of measurement errors made by an ARB-accredited verifier or an offset public registry. To be sure, they could pay the cost of a second, independent verification for each project, but that would be a significant cost. For these reasons, if insurers have to individually insure each project—and be ready to pay claims on that insurance for upwards of eight years—such insurance will be cost-prohibitive.

In other types of more mature and "natural" markets, the cost of insurance can come down if offered on the basis of large pools, in which case invalidation risks can be spread among numerous and diverse activities or individuals. However, there is no mechanism in the offset regulations that makes such pooling possible for private insurers. As a result, any insurers for the ARB offsets market will have to build up such pools on their own over time and at very high cost—and these costs will be passed through to covered entities in their rates.

In addition, in order to be prepared to pay out on claims, each insurer will have to amass a buffer account of allowances and offset credits. This means that there will be additional players in the market buying up allowances and offset credits and passing the costs of these purchases through to covered entities in insurance rates. Carbon prices will also be higher than they would otherwise be because there will fewer allowances and offset credits available to covered entities to use for compliance because of this additional buying by insurers to maintain their own buffer accounts.

Finally, even where such insurance becomes available, our members' experience is that insurers will refuse to cover "market risk." In other words, if the market price of offset credits increases from the time the insurance is purchased, insurers will not cover that difference. Thus, even "high-end" insurance products will fall short, forcing buyers of offset credits effectively to self-insure for some portion of their risk. We have noted that the proposed regulations now authorize offset project registries to offer (but not mandate) insurance. However, for at least two reasons, it is our view that registries will not provide a workable insurance pathway. First, registries have a conflict of interest. As ARB's own regulations recognize, registries themselves could be the source of a credit discrepancy. Second, registries are not well capitalized, and therefore could not be relied upon to pay out on claims. Without a balance sheet, a registry would not be in a position to play the role of insurer.

Accordingly, experience suggests that viable and economical insurance products will not materialize under the buyer liability regime proposed by ARB. The insurance products that do emerge will be available only at very high prices, which will severely impair the ARB offsets program. The need to obtain high-priced insurance will amount to a substantial and unnecessary cost to the offsets program, crowding out small projects and small businesses. Far fewer offset credits will be used in the program, including from offset projects that otherwise could pass all of the program's environmental rules with flying colors. Again, this outcome will drive the regulations far closer to the "no-offsets" side of the cost spectrum. (CERP4)

> **Response:** We believe that given all of the clarifications to section 95985, the market should be able to quantify and cover the risk associated with invalidation. We expect that insurance products will emerge once the market has been established, and nothing limits such mechanisms to come from offset project registries.

M-109. Comment: Some ARB officials have asserted that buyers can easily manage their liability risk by entering into contracts with offset project operators that force the latter to pay penalties for invalidated credits. However, this view is not consistent with marketplace realities. Managing the risk through contracts is not feasible.

Such contractual provisions will unleash a chain of contractual claims involving not only the buyer and the offset project operator but also every other party that held custody of the invalided offset credit prior to it being invalidated. The buyer will turn in the first instance to the party that sold the invalidated offset credit to it; this party will then go to the party from whom it received such credit; and so forth down the chain until the offset project operator is reached. Each receiving party of the invalidated offset credit will seek to enforce a contractual claim for damages on the delivering party. Resolving this chain of claims will be hugely time-consuming and costly; it will paralyze the market, and strongly discourage covered entities (especially small businesses) from ever venturing to buy offsets at all.

These outcomes will have seriously adverse effects on the offset program. In effect, aggregators, who intermediate between covered entities and offset project operators by sourcing and developing projects and sell the resulting offset credits to covered entities, will be forced out of the market. This is because no aggregator will guarantee delivery of offset credits to a buyer if there is a possibility that the aggregator will face a contractual claim against it in the event an offset credit is invalidated for reasons beyond its control.

The exit of aggregators will have real consequences. Aggregators play the crucial role of providing covered entities—especially small- and medium-sized businesses that have limited resources—with offsets credits to which they would not otherwise have access. Managing offset credits requires technical expertise and infrastructure that is costly to maintain, and generally beyond the ability of all but the largest covered entities. If aggregators are foreclosed from the market, then far fewer covered entities will use far fewer offsets.

Without aggregators, the offsets market will consist, if it exists at all, of bilateral arrangements between covered entities and individual projects. Even bilateral contracts will require covered entities to count on enforcing these contracts several years into the future. In reality, it is very difficult and costly for covered entities to rely on contract clauses to “carry” for eight years the risk that they suddenly will face a 90-day clock to replace credits.

Such bilateral deals will be manageable only by the largest covered entities, and such entities will be interested only in the largest projects. Covered entities likely will not find it worthwhile to deal with smaller projects—which are the kinds of projects likely to be located in California.

With such a stunted offsets program, allowance prices will necessarily increase in order to provide incentives for the more costly abatement needed to meet the cap. In the end, we will be much closer to the “no-offsets” end of the spectrum. (CERP4)

Response: We do not agree that we should eliminate buyer liability associated with the invalidation of ARB offset credits. Requiring the user to replace the invalidated offsets ensures that purchasers and users of offset credits do their due diligence in seeking out high-quality offset credits. We have clear enforcement authority over covered entities that will be using ARB offsets for compliance. If the covered entity replaces any invalidated offset credits, they may then take appropriate action through third-party contractual arrangements that they may have established prior to purchase. These arrangements currently exist in the voluntary offset market, and we expect that as the offset market becomes more established, that additional mechanisms to deal with the risk of invalidation will also be established. In the event that the offset credit has not yet been used or retired, it will be canceled in the market tracking system and removed from any Holding or Compliance Accounts. These provisions in no way diminish our authority to assess penalties under section 96014 on any offset project developer or verifier that has provided false information to ARB.

We are not convinced that aggregators will be pushed out of the market in response to our policies. The new clarifications will provide quantification of risk and still ensure that every party, including aggregators, conducts due diligence in trading offset credits.

M-110. Comment: Set up a buffer pool for all offset projects. A problem associated with ARBs' "buyer liability" approach is determining which offsets get invalidated. If ARB finds a discrepancy, will an entire vintage year or years of offsets from a project be deemed invalid or just the shortfall? Unless all the offsets are purchased by the same entity, ARB will be saddled with determining which entity is holding invalid offsets. For instance if ARB determines the accreditation of offsets is overstated by more than 5 percent, which offsets within the total lot for that year will be invalidated? Will it be the first offsets generated, the last, or some in the middle? This would cause offsets within the same lot to potentially be offered at different prices. ARB will have to determine which offset credits no longer have value. In turn, ARB will have to develop a mechanism that is fair and unbiased in order to make this determination. ARB's effort to protect the integrity of the offset system is commendable however it has created a level of complexity and element of risk that is unnecessary. The adjustment of the accreditation and verification process to lock in a verified offset after eight or even five years is a step in the right direction. This will alleviate some of the risk this approach presents to buyers and developers but does not completely eliminate the problems associated with this approach. ARB needs to attack the issue on the front end rather than just reacting to an error. NextEra proposes ARB establish a buffer pool of allowances to protect the offset program in the event of a project going bankrupt or a large reversal of sequestration. In addition, credits should be considered irrevocable after they are certified by an accredited verifier. In the case of any calculation errors or discrepancies like those listed in the proposed rule modifications, the offsets should be deducted from a future year offset vintage that has not been transferred to another entity to account for the shortfall. One option would be to take and replace offset credits from the buffer pool. This way the integrity of the program remains intact since the faulty or overstated offsets have been replaced and the risk to the buyer is eliminated. (NEXTERAENERGY2)

> **Response:** We do not agree that we should eliminate buyer liability associated with the invalidation of ARB offset credits. Requiring the user to replace the invalidated offsets ensures that purchasers and users of offset credits do their due diligence in seeking out high-quality offset credits. We have clear enforcement authority over covered entities that will be using ARB offsets for compliance. If the covered entity replaces any invalidated offset credits, they may then take appropriate action through third-party contractual arrangements that they may have established prior to purchase. These arrangements currently exist in the voluntary offset market, and we expect that as the offset market becomes more established, that additional mechanisms to deal with the risk of invalidation will also be established. In the event that the offset credit has not yet been used or retired, it will be canceled in the market tracking system and removed from any Holding or Compliance Accounts. These provisions in no way diminish our authority to assess penalties under section 96014 on any offset project developer or verifier that has provided false information to ARB.
>
> We included extensive modified provisions in section 95985 to make it clear what would trigger an invalidation, how we will invalidate offsets, and which offsets will need to be replaced. We believe that these changes provide clarity on this point.
>
> In addition, we included new section 95985(c)(1)(A)) which includes provisions for ARB to invalidate the overage of credited GHG reductions and GHG removal enhancements. Under this provision, we will only invalidate the number of ARB offset credits that correspond to the overstated GHG reductions and GHG removal enhancements and not 100 percent of the ARB offset credits in that Offset Project Data Report. We also included a procedure for how we will determine which serial numbers we will invalidate. We believe this will maintain the environmental integrity because any overage will immediately be compensated. These provisions address stakeholder concerns that projects will be unfairly penalized for small calculation mistakes.

M-111. Comment: In the case of offset discrepancies, it almost certainly will be the offset project operator, verifier, or offset project registry that is at fault—and, under Regulation, each of these parties submits to the jurisdiction of ARB. Yet, under ARB's proposed buyer liability rules, the holder or user of a credit is presumptively liable. This arrangement turns fairness on its head, as the party less likely to be responsible for the issue bears the cost, while the parties that may be responsible bear no direct cost. This approach does not encourage offset project operators and verifiers to be careful and conservative. In addition, the approach is highly inefficient. To be efficient, a liability system should impose liability on the party that has the most information and ability to control performance. Most covered entities do not have any special insight into methane digesters, ozone-depleting substances, or forestry. In an offsets program, covered entities will rely on the work of verifiers—and on ARB itself as credit issuer. For this reason, making covered entity buyers liable for problems not detected through the regulatory system would impose substantial new costs on buyers without materially reducing the risk that such problems will occur. ARB officials also have asserted that buyers can easily and efficiently manage their liability risk through contracts. This view is not consistent with marketplace realities because of informational asymmetries between buyers (less informed) and sellers (better informed). A viable offsets program will involve the participation of many buyers and sellers—including aggregators who intermediate between smaller covered entities and offset project operators. A buyer liability rule implies a market in which invalidation would unleash a chain of contractual claims involving every party that ever held custody of the credit, paralyzing the marketplace. Aggregators and small businesses will avoid such a market—leaving a stunted offsets program involving only bilateral arrangements by largest covered entities for the largest projects. Small businesses and small projects will fall out of the equation. Some ARB officials see insurers coming to the rescue. For several reasons, SCPPA is skeptical about the emergence of viable insurance products. Insurers typically assess and insure against risks that apply to private activities or enterprises. In an offsets market, by contrast, the risk relates to the performance of a government program—and the ARB offsets system is a government program with no track record of experience. Cost-effective insurance will not materialize in such a small and idiosyncratic market, where the insurance products would have to change over time to match regulatory requirements. In other types of more mature and "natural" markets, the cost of insurance can come down if offered on the basis of large pools of varying risks. However, there is no mechanism in the Regulation that makes such pooling possible for private insurers. As a result, any insurers for the ARB offsets market will have to build up such pools on their own over time and at very high cost—and these costs will be passed through to covered entities in their rates. Finally, SCPPA is skeptical that offset project registries can provide a workable insurance pathway. First, as ARB's own Regulation recognizes, registries themselves could be the source of a credit discrepancy. [See section 95985(b)(1) (providing that a grounds for invalidation includes a determination by ARB that "information provided to ARB for an Offset Project Data Report or Offset Verification Statement by offset verifiers, verification bodies, Offset Project Operators, Authorized Project Designees, or *Offset Project Registries,* related to an offset project was not true, accurate, or complete") (emphasis added).] Second, registries are not well capitalized, and therefore could not be relied upon to pay out on claims. For these reasons, ARB Should Apply the Forest Buffer Account Approach to All Offsets. ARB has included in the Regulation a buffer account that applies for post-issuance problems associated with forest offset projects. SCPPA strongly urges the ARB to apply this Forest Buffer Account approach to all offset projects. The integrity of the emissions cap would be maintained by retiring additional offsets from the buffer account if any problems arise, and offsets would not need to be invalidated. Compared to the buyer liability system, this approach would be:

- equally effective in making the system whole in the event of invalid credits;
- far fairer (by holding "bad actors" liable where possible); and
- much more efficient (again by holding bad actors liable, but also including a systemwide backstop).

ARB has not explained why this kind of approach is workable and appropriate for forest offset projects, but not for other offset project types. In particular, ARB has not explained why extending this approach to all offset projects would impose unreasonable administrative or risk burdens on the agency. SCPPA does not believe such burdens would result. The primary role of ARB under the buffer account approach is to determine the portion of offset credits to set aside in the account. This set-aside should be conservative. In any event, ARB would have the ability to increase the amount of the set-aside if the buffer account runs low. The account requires no active management, and no purchase or sale of offsets. It is not a bank account. The offset buffer account would not be the primary recourse. First, the ARB should identify the entity responsible for the problems with the offsets, and require that entity to provide additional compliance instruments or face penalties. If the responsible entity fails to provide additional compliance instruments, ARB will retire a corresponding amount of offset credits from the Offset Buffer Account. This is similar to the approach taken with the Forest Buffer Account. To implement the buffer approach discussed above, a definition of “Offset Buffer Account” is required, as a new subsection in section 95802(a). A proposed definition is set out below, mirroring the existing language for the Forest Buffer Account. Modify section 95802 (a) as follows:

> (a)<u>(X) “Offset Buffer Account” means a holding account for ARB offset credits. It is used as a general insurance mechanism against failure to surrender additional compliance instruments under section 95985(f) when ARB has made a determination pursuant to Section 95985 (e)(4).</u> (SCPPA6)
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> **Response:** We do not agree that we should eliminate buyer liability associated with the invalidation of ARB offset credits. Requiring the user to replace the invalidated offsets ensures that purchasers and users of offset credits do their due diligence in seeking out high-quality offset credits. We have clear enforcement authority over covered entities that will be using ARB offsets for compliance. If the covered entity replaces any invalidated offset credits, they may then take appropriate action through third-party contractual arrangements that they may have established prior to purchase. These arrangements currently exist in the voluntary offset market, and we expect that as the offset market becomes more established, that additional mechanisms to deal with the risk of invalidation will also be established. In the event that the offset credit has not yet been used or retired, it will be canceled in the market tracking system and removed from any Holding or Compliance Accounts. These provisions in no way diminish our authority to assess penalties under section 96014 on any offset project developer or verifier that has provided false information to ARB.
>
> We included extensive modified provisions in section 95985 to make it clear what would trigger an invalidation, how we will invalidate offsets, and which offsets will need to be replaced. We believe that these changes provide clarity on this point.
>
> In regard to insurance and risk management mechanisms, we believe that given all of the clarifications to section 95985, the market should be able to quantify

and cover the risk associated with invalidation. We expect that insurance products will emerge once the market has been established. As noted by the commenter, we have also included a role for Offset Project Registries to offer insurance mechanisms, such as a buffer account, for offset projects associated with their registries. While the regulation allows for this, we made it clear in the provision that market participants must not participate or purchase registry insurance.

The buffer account for forestry is necessary to account for reversals in the forest sector due to the issues surrounding permanence. We do not believe that non-sequestration projects pose the same risks, and that such a mechanism is only appropriate to account for sequestration-based reversals.

M-112. Comment: The OWG supports the use of offsets, within the limit established by ARB's regulations, as an effective cost containment tool for the cap and trade program. However, the OWG is concerned that there will be insufficient supply of offsets, and specifically in this context that ARB's current approach to invalidation will both constrain the supply and increase the costs of offsets. The OWG believes that it will not be easy or cost-effective to insure the risk of offset invalidations through traditional insurance markets. Nor does the OWG believe that including language in contracts that will pass the risk from the buyer to the original developer (or someone up the contract chain) will work well, as indications from the market is that many offset project developers will not entertain such clauses**.** Some counterparties may not be willing to enter contracts obligating an entity other than the buyer, and OPOs are in the best position to understand whether particular offset credits have a risk of invalidation. Instead of placing a strict liability on buyers, the OWG recommends that ARB establish a Compliance Buffer Pool (CBP) that is separate but similar to ARB's Forest Buffer Pool. The CBP would be filled with a fraction of all offset credits surrendered to ARB for compliance. ARB could use a risk factor for each type of offset project. For example, the OWG expects that the chance of invalidation for ODS and livestock methane projects is slight. Therefore, ARB could begin filling its CBP with a very low percentage of credits from each lot that is surrendered, possibly 0.5%. This would create a minimal impact on the price of offsets, and yet achieve significantly more certainty for buyers as a whole. If ARB does establish a CBP, the OWG recommends that the regulations include a review by ARB after the first triennial compliance period. Pursuant to this review, ARB could then determine whether the 0.5% (as used in the OWG's example) was too high, too low, or sufficient to cover the invalidations actually observed during that time period. (OFFSETSWG3)

Response: We do not agree that we should eliminate buyer liability associated with the invalidation of ARB offset credits. Requiring the user to replace the invalidated offsets ensures that purchasers and users of offset credits do their due diligence in seeking out high-quality offset credits. We have clear enforcement authority over covered entities that will be using ARB offsets for compliance. If the covered entity replaces any invalidated offset credits, they may then take appropriate action through third-party contractual arrangements that they may have established prior to purchase. These arrangements currently exist in the voluntary offset market, and we expect that as the offset market becomes more established, that additional mechanisms to deal with the risk of invalidation will also be established. In the event that the offset credit has not yet been used or retired, it will be canceled in the market tracking system and removed from any Holding or Compliance Accounts. These provisions in no way diminish our authority to assess penalties under section 96014 on any offset project developer or verifier that has provided false information to ARB.

In regard to insurance and risk management mechanisms, we believe that given all of the clarifications to section 95985, the market should be able to quantify and cover the risk associated with invalidation. We expect that insurance products will emerge once the market has been established.

We do not agree that there will be insufficient offset supply in the first compliance period. We recently estimated that if every entity used their allowable eight percent offsets, approximately 26 million metric tons of offsets would be needed in the first compliance period. This reduced need is due to a start of the first compliance period in 2013 instead of in 2012. At this time, based on the four offset protocols the Board has endorsed—manure digesters, forestry, urban forestry, and destruction of ozone depleting substances—ARB will be close to the supply demand for the first compliance period. We also will propose additional Compliance Offset Protocols for Board consideration beginning in 2012.

M-113. Comment: Offset liability in the proposed modifications allows for certainty for the market to develop insurance. However, if this insurance market is either very expensive or does not meet the needs of the covered entities, the buyers and the developers of offsets will face increased transaction costs and market uncertainty. This will increase costs to all in the market. In contrast, ARB, assumed that insurance will meet the needs of the market. We propose that ARB review this assumption in early 2013 using, as a criteria, both the existence of insurance and the actual use of it by covered entities. Early review of the availability and use of insurance to address offset liability is essential to prevent offset supply issues that will arise in 2015, caused by the long lead times needed to develop offsets. All of these issues, the lack of available protocols, the chilling effect on the market from the offset liability costs, and the overly prescriptive ARB approval process, have the serious potential to limit the amount of offsets and reduce the ability of the market to function efficiently to achieve emission reductions cost-effectively. ARB must be more aggressive in promoting the use of offsets. This would be accomplished by: i) increasing the speed at which offset protocols are adopted; ii) streamlining the process by reducing the prescriptive details of the approval process, iii) focusing on approving independent offset approval agencies to issue usable offsets to reduce bottlenecks and increase the supply of offsets and iv) adopting policies to either provide a buffer account or review the availability and use of insurance in early 2013. (WSPA3)

Response: We recognize stakeholder concerns regarding offset supply. We do not agree that there will be insufficient offset supply in the first compliance period. We recently estimated that if every entity used their allowable eight percent offsets, approximately 26 million metric tons of offsets would be needed in the first compliance period. This reduced need is due to a start of the first compliance period in 2013 instead of in 2012. At this time, based on the four offset protocols the Board has endorsed—manure digesters, forestry, urban forestry, and destruction of ozone depleting substances—ARB will be close to the supply demand for the first compliance period.

ARB may not adopt additional protocols as part of this cap-and-trade rulemaking. All offset protocols used in the compliance program must be adopted by the Board after undergoing a full regulatory process, including an ARB stakeholder process, in accordance with the Administrative Procedure Act, and an environmental review. We plan to look at further offset protocols for potential inclusion in the cap-and-trade program beginning in 2012. The details surrounding any new offset project types for which ARB adopts an offset protocol will be dealt with under that specific rulemaking, and modification will be made to the cap-and-trade regulation as needed.

ARB has provided a role for Offset Project Registries (OPR) to perform some of the administrative functions of the offset process in the regulation. We plan to utilize OPRs in lieu of having ARB perform these duties in the short-term, and may choose to continue this approach throughout the program. We have not yet determined if and when ARB would perform these roles. Therefore, in the meantime, all parties seeking to use Compliance Offset Protocols must go directly to an OPR to list their projects. We plan to approve OPRs sometime in 2012.

M-114. (multiple comments)
Comment: Iberdrola Renewables agrees that offsets will be an important part of the cap-and-trade regulation to provide options for entities with compliance obligations. Iberdrola Renewables is concerned by the proposed ability for CARB to invalidate a previously validated offset credit up to eight years after issuance. The existing provision for offset invalidation will create risk and uncertainty in the offset market, and place liability on entities holding or using offset credits to meet their compliance obligation. The end result will be an inefficient offset market comprised only of bilateral agreements between large entities, as small businesses and projects will not be able to absorb the resulting contractual complexity, eight years of subsequent performance assurance, and compliance and other risks presented by retroactivity. If clear requirements for offset verification and certification are established, a mechanism for revocation should not be required. (IBERDROLA)

Comment: IETA understands and shares California's desire to maintain the environmental integrity of the emissions cap, but believes that providing ARB with the ability to invalidate issued offset credits is the wrong avenue to do so. A proposal to invalidate issued offsets is likely to threaten compliance, increase administrative costs, and decrease offset supply. Because of this, IETA's first recommendation is to establish rigorous offset verification and subsequent certification standards to ensure only quality offsets enter the market. With confidence in every issued offset, retaining the right to revoke offset credits is simply unnecessary. However, if ARB insists on retaining the ability to revoke issued offset credits, IETA's second recommendation would be for California to adopt a forest buffer account approach on all offsets. We note that ARB has included in the proposed Regulations a buffer account that applies for post-issuance problems associated with forest offset projects. IETA strongly urges ARB to apply this Forest Buffer Account to all offset projects. Compared to the buyer liability system, this approach would be: (1) equally effective in making the system whole in the event of invalid credits; (2) far fairer (by holding "bad actors" liable where possible); and (3) much more efficient (again by holding bad actors liable, but also including a system-wide backstop). Why should this kind of approach be workable and appropriate for forest offset projects, but not for other offset project types? IETA would like to reiterate its proposal modeled roughly on a forest buffer account for unintentional reversals that (1) provides absolute assurances of environmental integrity, and (2) avoids imposing undue administrative risks or costs. IETA's proposal, which is explained in greater detail in the appendix, works as follows:

- Before issuing credits to an offset project, ARB would hold back a certain percentage of credits and place the credits in a Compliance Buffer Account (CBA).
- In the event that ARB determined that documentation supporting an offset credit is materially not true, accurate or complete, then ARB would immediately retire credits from the CBA to replace those that had been invalidated.
- In the event that the credits were invalidated due to a discrepancy that resulted from willful intent or gross negligence, ARB would seek to replenish the credits retired from the CBA from the entity actually responsible for the discrepancy. Requiring the CBA to be replenished in this manner will ensure the long-term viability of the CBA and guard against the moral hazard of lax compliance with the offset program.
- In any event, the credits already issued would remain unaffected, but the program would be made whole by retiring credits from the Compliance Buffer Account.

Under this proposal, the market itself, not ARB, bears the risk of flawed credits. In our view, this approach is just as effective in ensuring environmental integrity, but far more efficient and consistent with a robust market. A CBA provides an ironclad compliance backstop resulting in more emissions, reducing offset projects without imposing unreasonable administrative burdens on California. We understand ARB is reluctant to take on additional administrative or risk burdens, but IETA does not believe such burdens would result. The primary role of ARB under this compliance buffer account approach is to determine the portion of offset credits to set aside in the account. We believe this set-aside should be conservative. In any event, ARB would have the ability to increase the amount of the set-aside if the buffer account runs low. The account requires no active management. It is not a bank account. (IETA3)

Response: We do not agree that we should eliminate buyer liability associated with the invalidation of ARB offset credits. Requiring the user to replace the invalidated offsets ensures that purchasers and users of offset credits do their due diligence in seeking out high-quality offset credits. We have clear enforcement authority over covered entities that will be using ARB offsets for compliance. If the covered entity replaces any invalidated offset credits, they may then take appropriate action through third-party contractual arrangements that they may have established prior to purchase. These arrangements currently exist in the voluntary offset market, and we expect that as the offset market becomes more established, that additional mechanisms to deal with the risk of invalidation will also be established. In the event that the offset credit has not yet been used or retired, it will be canceled in the market tracking system and removed from any Holding or Compliance Accounts. These provisions in no way diminish our authority to assess penalties under section 96014 on any offset project developer or verifier that has provided false information to ARB.

We do not agree that an offset credit should remain viable under all conditions. To ensure the enforceability of compliance offsets, we need to have the ability to investigate and take action for violations or noncompliance with the proposed regulation. In the event of fraud or malfeasance on the part of project developers or verifiers, there may be cause to invalidate offset credits after they have been issued, to protect the environmental integrity of the program.

M-115. Comment: IEP recommends that the CARB pursue an offset program in which credits, once certified, are non-revocable. Alternatively, if CARB continues to pursue a program where certified and verified offset credits are revocable, all invalidated offsets should be treated similar to the requirements for forest offset projects [section 95895(g)] in which the forest owner must replace each invalidated ARB offset credit with a valid ARB offset credit or another approved compliance instrument. Offset credits, once issued, should not be revocable by CARB. Alternatively, CARB should remove provisions that make the buyer liable for invalidation, and instead place the liability to replace the offset credit on the offset project operator. Also, revise the regulation so that an offset credit can only be invalidated within one year after the offset is issued.

1. Delete Section 95985: Invalidation of ARB Offset Credits.
2. Alternatively, modify section 95985(f) and section 95985(b) as follows:

(f) Requirements for Non-Sequestration Offset Projects. If an ARB offset credit is found to be invalid pursuant to sections 95985(b) and (d) the party identified in section 95985(c)~~(2)~~ (3) must replace each ARB offset credit with a valid ARB offset credit or another approved compliance instrument pursuant to subarticle 4, within 90 calendar days of notification by ARB pursuant to section 95985(e). If the party identified in section 95985(c)~~(2)~~ (3) does not replace each invalid ARB offset credit within 90 calendar days of the notice of invalidation pursuant to section 95985(e), each outstanding ARB offset credit will constitute a violation pursuant to section 96014. ~~If the party identified in section 95985(c)(2) is no longer in business ARB will require the Offset Project Operator or Authorized Project Designee to replace each invalidated ARB offset credit and~~

~~will notify the Offset Project Operator or Authorized Project Designee that they must replace them. The Offset Project Operator or Authorized Project Designee must replace each ARB offset credit with a valid ARB offset credit or another approved compliance instrument pursuant to subarticle 4, within 90 calendar days of notification by ARB pursuant to section 95985(e). If the Offset Project Operator or Authorized Project Designee does not replace each invalid ARB offset credit within 90 calendar days of notification by ARB pursuant to section 95985(e), each outstanding ARB offset credit will constitute a violation pursuant to section 96014.~~

Section 95985
(b) ARB may determine within ~~8~~1 year~~s~~ of issuance, ~~except as provided in section 95985(b)(5) and (6),~~ that an ARB offset credit is invalid for the following reasons:
(1) ARB determines that information provided to ARB for an Offset Project Data Report or Offset Verification Statement by offset verifiers, verification bodies, Offset Project Operators, Authorized Project Designees, or Offset Project Registries, related to an offset project was not true, accurate, or complete; or
(2) The Offset Project Data Report contains errors that overstate the amount of GHG reductions or GHG removal enhancements by more than 5 percent; or
(3) The offset project did not meet all local, state, or national regulatory requirements during the time covered by an Offset Project Data Report; or
(4) ARB determines that offset credits have been issued in any other voluntary or mandatory program within the same offset project boundary or for the same GHG reductions or GHG removal enhancements covered by an Offset Project Data Report.
(5) If an offset project is developed under Compliance Offset Protocol U.S. Ozone Depleting Substances Projects, ARB may invalidate within ~~five~~ one year~~s~~ of issuance of the ARB offset credits covered by an Offset Project Data Report.
(6) If an offset project is verified after three years of ARB offset credit issuance by a different offset verifier, ARB may invalidate within ~~five~~ one year~~s~~ of issuance of the ARB offset credits covered by an Offset Project Data Report.
(7) An update to a Compliance Offset Protocol in itself, will not result in an invalidation of ARB offset credits issued under a previous version of the Compliance Offset Protocol. (IEPA2)

Response: We do not agree that we should eliminate buyer liability associated with the invalidation of ARB offset credits. Requiring the user to replace the invalidated offsets ensures that purchasers and users of offset credits do their due diligence in seeking out high-quality offset credits. We have clear enforcement authority over covered entities that will be using ARB offsets for compliance. If the covered entity replaces any invalidated offset credits, they may then take appropriate action through third-party contractual arrangements that they may have established prior to purchase. These arrangements currently exist in the voluntary offset market, and we expect that as the offset market becomes more established, that additional mechanisms to deal with the risk of invalidation will also be established. In the event that the offset credit has not yet been used or retired, it will be canceled in the market tracking system and removed from any Holding or Compliance Accounts. These provisions in no way diminish our authority to assess penalties under section 96014 on any offset project developer or verifier that has provided false information to ARB.

We do not agree that an offset credit should remain viable under all conditions. To ensure the enforceability of compliance offsets, we need to have the ability to investigate and take action for violations or noncompliance with the proposed regulation. In the event of fraud or malfeasance on the part of project developers or verifiers, there may be cause to invalidate offset credits after they have been issued, to protect the environmental integrity of the program.

Section 95985(b) was modified to establish a statute of limitations for the invalidation of ARB offset credits of three years if the Offset Project Data Report or a subsequent Offset Project Data Report, depending on project type, is verified by a different verifier within that time frame. If the offset project does not qualify under these requirements, the default statute of limitations is eight years. We believe that the three-year time period is sufficient to uncover any new information, as long as the project has been reviewed by a second verifier. If it is not looked at by a second verifier, we believe that eight years is necessary to uncover any new information that could lead to the invalidation of ARB offset credits. We believe the eight-year statute of limitations is sufficient because it would allow two verification parties to examine the offset credits in question for continuous projects. We do not believe that one year would provide sufficient time to detect all relevant new information or uncover any mistakes that a verifier may have missed.

M-116. Comment: We have serious concerns about ARB's "buyer liability" approach to addressing situations in which problems are identified with offset credits after they have been issued. At present, buyer liability will undermine a liquid, and efficient market open to all. Instead, offsets will become a high-risk private investment exercise suited only to a small number of specialist intermediaries. It will prevent the development of a market in offsets, limit allowance supply for California large emitters, and may increase compliance costs. Buyer liability will significantly increase the overall cost of the California Cap and Trade Program. Buyers of offset allowances will demand lower prices to reflect their risk that offset allowances could be invalidated. This will likely result in a large discount for offset allowances relative to non-offset allowances. Low pricing will not provide the necessary incentive for emission reduction project to be developed. ARB modeled the Regulations under a scenario in which no offsets could be utilized. Relative to the baseline case (in which offsets are utilized to the full 8 percent limit), ARB's modeling concluded that this "no offsets" scenario would yield allowance prices in 2020 that would be $108 higher ($148/ton instead of $30/ton)—resulting in $18 billion more in costs in that year alone. The current buyer liability approach effectively will drive the AB 32 program toward the "no offsets" scenario, resulting in significantly increased compliance costs. Some ARB officials see insurers coming to the rescue. For several reasons, we are skeptical about the emergence of viable insurance products. Insurers typically assess and insure against risks that apply to private activities or enterprises. In an offsets market, by contrast, the risk relates not only to identifiable actor failures to perform, but also to the performance of a government program. This form of regulatory risk is very difficult to measure in general, but more so in a new and untested regime. Cost-effective insurance will not materialize in such a small and idiosyncratic market. Under similar programs, companies have attempted to secure third party coverage from large insurers as well as re-insurers to mitigate buyer liability risk. Both internationally and domestically, these efforts have failed to yield a satisfactory insurance product covering compliance exposure. This risk is difficult for insurance markets to quantify because one ton of offset allowance may or may not have equivalent monetary value between two periods; and the market replacement cost may only cover part of the exposure. In the end, it is more than a market risk issue. It contains elements of regulatory, reputational and market risk. That part of the equation has proven to be unquantifiable in many instances, particularly over very long time periods. The proposed rules also contemplate that offset project registries may offer voluntary insurance products to protect against buyer liability risks." We are skeptical that offset project registries can provide a workable insurance pathway. First, as ARB's own regulations recognize, registries themselves could be the source of a credit discrepancy." Second, registries are not sufficiently capitalized, and even with third party balance sheet support (insurance), cannot necessarily be relied upon to pay out claims. We believe that the ARB should reconsider offset invalidation procedures and instead rely on the pre-issuance process. Multiple verifications over sequential operating periods can provide the necessary safeguards. If enough security cannot be provided pre-issuance, then we further encourage the consideration of a much shorter period over which issued offsets can be subject to invalidation proceedings. Post issuance, multiple verifications of sequential operating periods together with rotating verifier assignments could support a shorter "at-risk" period and provide comfort. We believe an aggressive and secure pre-issuance process can provide regulators with the certainty to issue offsets permanently. Absent relying on a secure issuance, ARB could consider an alternative to the cancelling of credits that would not impair the compliance value of issued offsets. Swapping and cancelling equal numbers of viable offsets in a compliance buffer account for offsets subject to invalidation proceedings could relieve this risk. Alternatively, ARB could follow the procedure for invalidating CERS and require verification bodies that wrongly verify offset allowances to procure and extinguish an equal number of allowances. However, should the Board retain the offset invalidation rules as they are currently proposed, the statute of limitations on the invalidation of offsets could be reduced from eight to not more than two years. These measures will help ensure that normal market transaction rules reduce cost and increase market transparency and fairness. (BARCLAYS)

Response: We do not agree that we should eliminate buyer liability associated with the invalidation of ARB offset credits. Requiring the user to replace the invalidated offsets ensures that purchasers and users of offset credits do their due diligence in seeking out high-quality offset credits. We have clear enforcement authority over covered entities that will be using ARB offsets for compliance. If the covered entity replaces any invalidated offset credits, they may then take appropriate action through third-party contractual arrangements that they may have established prior to purchase. These arrangements currently exist in the voluntary offset market, and we expect that as the offset market becomes more established, that additional mechanisms to deal with the risk of invalidation will also be established. In the event that the offset credit has not yet been used or retired, it will be canceled in the market tracking system and removed from any Holding or Compliance Accounts. These provisions in no way diminish our authority to assess penalties under section 96014 on any offset project developer or verifier that has provided false information to ARB.

Section 95985(b) was modified to establish a statute of limitations for the invalidation of ARB offset credits of three years if the Offset Project Data Report or a subsequent Offset Project Data Report, depending on project type, is verified by a different verifier within that time frame. If the offset project does not qualify under these requirements, the default statute of limitations is eight years. We believe that the three-year time period is sufficient to uncover any new information, as long as the project has been reviewed by a second verifier. If it is not looked at by a second verifier, we believe that eight years is necessary to uncover any new information that could lead to the invalidation of ARB offset credits. We believe the eight-year statute of limitations is sufficient because it would allow two verification parties to examine the offset credits in question for continuous projects.

As noted by the commenter, we have also included a role for Offset Project Registries to offer insurance mechanisms, such as a buffer account, for offset projects associated with their registries. While the regulation allows for this, we made it clear in the provision that market participants are not required to participate in or purchase registry insurance.

With regard to the comments related to the development of insurance, we believe that given all of the clarifications to section 95985 the market should be able to quantify and cover the risk associated with invalidation. We expect that insurance products will emerge once the market has been established.

M-117. Comment: PG&E appreciates the addition of section 95987(k) to the Regulations, allowing an Offset Project Registry to offset an insurance mechanism. An Offset Project Registry could serve as a third party administering a Compliance Buffer Account, but for such an account to be effective, contribution to the Account should be mandatory for all offset credit projects and triggers should be included to increase contribution to the Account if more than 50 percent of the offsets are withdrawn due to the provisions in section 95985. (PGE4)

> **Response:** As noted by the commenter, we have also included a role for Offset Project Registries to offer insurance mechanisms, such as a buffer account, for offset projects associated with their registries. While the regulation allows for this, we made it clear in the provision that market participants do not need to participate in or purchase registry insurance. It will be up to each registry to decide if and how to best establish an insurance mechanism.

M-118. (multiple comments)
Comment: IETA appreciates that ARB has extended the period of time from 30 days to 90 days that an invalidated credit must be replaced. Firstly, IETA believes that it should be the responsibility of the project owner or other relevant entity that committed the error (not the buyer) which leads to the invalidation to replace the offsets credits, as discussed above. Secondly, 90 days remains a very tight timetable for any entity to obtain replacement credits, particularly if it must obtain a large quantity. IETA respectfully urges ARB to further lengthen this period, and we do not believe that a longer period would impose any particular added burden on the program—or the climate. To this end, we note that the Regulations allow six months in the event of under-reporting of emissions for a covered entity to surrender additional compliance instruments. It is unclear why there should be a shorter period in the context of an ARB determination of offset invalidation under section 95985(c), and therefore respectfully urge ARB to modify the relevant provisions. (IETA3)

Comment: We urge ARB to allow for at least five months for replacement of offset credits with other compliance instruments in all circumstances (section 95983). It could prove very difficult for a market participant to acquire the necessary compliance instruments in 90 days, particularly if the market is illiquid at any given time. (NEWFOREST2)

Comment: We appreciate that ARB has extended the period of time from 30 days to 90 days that an invalidated credit must be replaced.

Firstly, we believe that it should be the responsibility of the project owner or other relevant entity that committed the error (not the buyer) which leads to the invalidation to replace the offsets credits, as discussed above.

Secondly, 90 days remains a very tight timetable for any entity to obtain replacement credits, particularly if it must obtain a large quantity. We respectfully urge ARB to further lengthen this period, and we do not believe that a longer period would impose any particular added burden on the program—or the climate.

To this end, we note that the regulations allow six months in the event of underreporting of emissions for a covered entity to surrender additional compliance instruments. Furthermore, in the context of an intentional reversal in a sequestration project, the regulations sensibly provide a year to determine the extent of the reversal. It is unclear why there should be a far shorter period in the context of an ARB determination of offset invalidation under section 95985(f), and therefore respectfully urge ARB to modify the relevant provisions. (CERP4)

> **Response:** We changed the timing for when the responsible party must replace the invalidated ARB offsets from 30 days to six months. This should provide enough flexibility for those that must replace invalidated offsets to purchase additional compliance instruments while still ensuing that the environmental integrity of the cap is maintained.

M-119. (multiple comments)
Comment: Most offset protocols incorporate a concept of materiality, in part in consideration of the fact that unintentional errors, minor measurement errors, etc. may occur that do not materially affect the GHG assertion. We believe it is not ARB's intent to invalidate ARB Offset Credits in the case of immaterial errors. We thus recommend adding the word to section 95985(b)(1): "ARB determines that information provided to ARB for an Offset Project Data Report or Offset Verification Statement by offset verifiers, verification bodies, Offset Project Operators, Authorized Project Designees, or Offset Project Registries related to an offset project was not <u>materially</u> true, accurate or complete;" (MARTINN3)

Comment: IETA respectfully requests that ARB eliminate section 95985(b)(1). Given the myriad requirements of the offset Regulations, any number of projects will have documentation that has inadvertent inaccuracies or omissions. Yet, under this vague and overbroad provision, a minor paperwork problem could result in invalidation of 100 percent of the offset credits already issued for a project, even if there was no impact on the reductions or removals actually achieve by the project. This is a draconian, "gotcha" approach that will deter development of offset projects for reasons unrelated related to environmental integrity. Furthermore, any discrepancies that *do* have material effects on the environmental integrity of the project are completely addressed by sections 95985(b)(2), (3), and (4). For these reasons, we respectfully urge ARB to eliminate section 95985(b)(1). (IETA3)

Comment: We urge to ARB modify the provisions under which offset credits may be invalidated. Currently, these include four conditions: the project information is not "true, accurate, or complete" (section 95985(b)(1)); the project documentation contains errors such that emission reductions achieved by the project are overstated by 5 percent or more (section 95985(b)(2)); the project did not meet all applicable legal requirements (section 95985(b)(3)); and a finding that credits already have been issued for the project in another program ((section 95985(b)(4)). We respectfully request that ARB eliminate (b)(1). Given the myriad requirements of the offset regulations, any number of projects could have documentation that has inadvertent inaccuracies or omissions. Yet, under this vague and overbroad provision, a minor paperwork problem could result in invalidation of 100 percent of the offset credits already issued for a project—even if there was no impact on the reductions or removals actually achieve by the project. This is a draconian, "gotcha" approach that will deter development of offset projects for reasons unrelated related to environmental integrity. Furthermore, any discrepancies that do have material effects on the environmental integrity of the project are completely addressed by (b)(2), (3), and (4). For these reasons, we respectfully urge ARB to eliminate (b)(1). Modify section 95985 as follows:

> (a) ARB may determine~~, within 8 years of issuance, except as provided in section 95985(b)(5) and 6, that an ARB offset credit is invalid for the following reasons:~~ at any time until the earlier of (i) a post-issuance verification of the Offset Project Data Report by a different offset verifier and (ii) 5 years ~~of~~ after issuance, that:
> ~~(1) ARB determines that information provided to ARB for an Offset Project Data Report or Offset Verification Statement by offset verifiers, verification bodies, Offset Project Operators, Authorized Project Designees, or Offset Project Registries related to an offset project was not true, accurate, or complete; or~~
> ~~(2)~~(1) The Offset Project Data Report contains errors that overstate the amount of GHG reductions or GHG removal enhancements by more than 5 percent (in which case, ARB shall determine the amount of offset credits that corresponds to the overstatement); or
> ~~(3)~~(2)The offset project did not meet all local, state, or national regulatory requirements during the time covered by an Offset Project Data Report; or
> ~~(4)~~(3)ARB determines that Offset credits have been issued in any other voluntary or mandatory program within the same offset project boundary or for the same GHG reductions or GHG removal enhancements covered by an Offset Project Data Report.
> ~~(5) If an offset project is developed under Compliance Offset Protocol U.S. Ozone Depleting Substances Projects, ARB may invalidate within five years of issuance of the ARB offset credits covered by an Offset Project Data Report.~~
> ~~(6) If an offset project is verified after three years of ARB offset credit issuance by a different offset verifier, ARB may invalidate within five years of issuance of the ARB offset credits covered by and Offset project Data Report~~
> ~~(7)~~(4)An update to a Compliance Offset Protocol in itself, will not result in an invalidation of ARB offset credits issued under a previous version of the Compliance Offset Protocol. (CERP4)

Comment: ARB should only invalidate those credits that are in excess of the actual value. If a second verifier discovers a material mistake that led to an overstatement of offset issuance by 10 percent, then 10 percent of the total issuance to that offset project data report should be retired from the buffer reserve. Invalidating all offset credits under an offset project data report is not necessary for any reason. It is only necessary if ARB is seeking to recover the invalidated offsets from participants ex post. If ARB adopts a buffer reserve approach, it could invalidate the appropriate amount while continuing to recognize valid emissions reductions or avoided emissions. (NEWFOREST2)

Comment: ARB should continue to provide additional clarification regarding the basis for and extent of offset credit invalidation. TNC commends ARB for providing additional clarification in the Regulations to identify the circumstances under which offset credits may be invalidated. Such clarity will help encourage investments in offset projects as market participants (forest owners, OPOs, capped entities, etc.) will have greater certainty and ability to manage risk. TNC recommends that ARB provide additional clarification to section 95985(b) by identifying the extent to which offset credits may be invalidated. For instance, subsection (b)(2) indicates that credits may be invalidated when the Offset Project Data Report overstates the amount of GHG reductions or removals by more that 5 percent. It is unclear from this provision whether all credits or just the portion that is overstated would be invalidated. Additional detail regarding the scope of invalidation or the process that will be used to determine the scope of invalidation for this subsection as well as the others in this provision would be useful. (NC8)

Comment: We recommend that ARB further refine the conditions in which credits are invalidated. No measurement is completely precise. We can expect offset project data reports to yield credit estimates that are higher and lower than the actual, true value. It is necessary and appropriate to invalidate credits when such errors (or outright fraud) are discovered. However, it makes no sense for ARB to invalidate all offset credits from an offset project data report due to any error that renders the report not “true, accurate or complete” in any way. ARB should strike section 95985(b)(1). The other provisions in this subsection address both fraud and significant errors, and this catch-all provision is unnecessary. If section 95985(b)(1) is retained, ARB should add a materiality qualifier so that offset project data reports are not invalidated due to immaterial errors that have no significant effect on offset credit issuance, e.g. “materially true, accurate or complete.” (NEWFOREST2)

> **Response:** We included extensive modified provisions in section 95985 to make it clear what would trigger an invalidation, how we will invalidate offsets, and which offsets will need to be replaced. We believe that these changes provide clarity on this point.

M-120. (multiple comments)
Comment: If emissions reductions are overstated by 5 percent or more, then ARB can invalidate all offsets generated by a project during the verification period. For smaller-scale projects, with many “moving parts” (e.g., cattle, generators, boilers, flares), it will be very unlikely that all of the credits from the verification period will be issued in error. It will be more likely that there could be a faulty meter or a calculation error or a missing piece of data that causes a downward revision of the reductions. In this case, there needs to be a provision for the number of offsets issued to be adjusted after the error is determined. We suggest that the project owner have the option of carrying out a re-verification and that a discount be applied retroactively to each offset

issued in the year where the misstatement has occurred. This should be relatively straightforward, as each offset will have a serial number linking it to a vintage year and project. (CIG2)

Comment: If the Board does ultimately decide to enact the buyer liability approach that it has proposed, the Board should make it clear that only invalidated offset credits that have been used for compliance (placed into a Compliance Account) need be replaced, rather than all invalidated credits (section 95985(f)). In an emissions trading system, if an incorrectly issued credit has not yet been used for compliance, its removal from the system is sufficient to ensure the system's atmospheric integrity. The holder of the invalidated credit should then be entitled to make its own decision regarding replacement with another offset or an allowance. (CAR4)

> **Response:** We agree and included provisions in section 95985 to clarify that only ARB offset credits in the Retirement Account must be replaced. ARB offsets credits that reside in any Holding or Compliance Accounts will be removed, but do not need to be replaced. We do not believe it is possible to list every type of situation under which a downward revision to an offset project data report is necessary, and did not add such text.

M-121. Comment: Section 95985(b)(7) provides that in itself, an update to a Compliance Offset Protocol "will not result in an invalidation of ARB offset credits issued under a previous version of the Compliance Offset Protocol." SCE applauds ARB's inclusion of this section. In order to promote the most effective and efficient offset reductions, the regulated community must have confidence that ARB will not reverse the approval it gave to an offset project or offset after it has been verified. However, SCE recommends that ARB add explicit language to this section stating that a protocol change cannot in any way influence a decision to reverse an offset. Modify section 95985(b)(7) as follows:

> (7) An update to a Compliance Offset Protocol ~~in itself~~, will not <u>in any way</u> result in an invalidation of ARB offset credits issued under a previous version of the Compliance Offset Protocol. (SCE3)

> **Response:** We agree and have added new section 95985(c)(4)(A).

M-122. Comment: It is improper for CARB to set aside a percentage of the total offsets into a fund that would be used to cover future invalidations. This hedge fund approach devalues an offset from the outset, and makes the seller assume the risk by giving away part of his asset, or the buyer pay more for less. (WM3)

> **Response:** We agree and will not be changing the responsible party for covering an invalidation.

M-123. Comment: We commend ARB for adopting a "statute of limitations" for invalidation. This is reasonable and reduces the uncertainty significantly. (MSCG3)

Response: Thank you for your support.

M-124. (multiple comments)
Comment: Section 95985(b) gives ARB the sole authority to invalidate credits. WSPA believes that invalidation should be judged by impartial third party. WSPA recommends that this section be amended to incorporate input and recommendations from an impartial third party. (WSPA3)

Comment: In section 95985(h), the reference to not precluding the "State of California" from taking enforcement action should be broadened to include any entity authorized by law to enforce the provisions of this Regulation. (SCAQMD4)

Response: We disagree that a third-party should make determinations regarding invalidations. We are the only party that can regulate the compliance offsets market and determine which ARB offset credits are valid. We already receive input from third parties through the third-party verification process and the offset project registries. We have sole responsibility to enforce this regulation and do not believe it is appropriate to delegate that authority to another entity.

M-125. Comment: ARB should use the forest offset buffer pool for invalidation of forest offsets in the same manner it relies on the pool for intentional reversals to avoid inconsistencies. In the event of an intentional reversal of forest offsets, the current draft of the Regulation (Subarticle 13, section 95983(c)(3)) requires the forest owner to replace these reversed tons with valid offset credits or other compliance instruments. TNC recommends that this replacement responsibility be assigned to the OPO since this party, according to the “forest owner” definition, is effectively the forest owner. In instances where intentionally reversed forest offsets are not replaced within 90 calendar days, ARB relies on the forest buffer account to replace the reversed tons. In the case of forest offsets, there may be instances where there is little difference between an intentional reversal and the invalidation of a forest offset. For instance, a party may intentionally harvest timber in a forest offset project area that effectively reverses (or reduces) offset credit that has already been attributed to a compliance obligation. This action could qualify as an intentional reversal, triggering the remedial process of section 95983(c)(3). At the same time, this intentional reversal could also qualify for offset credit invalidation pursuant to section 95985(b)(1) or (b)(2) as the reversal could be characterized as information that was not accurate or as a data report that overestimated the amount of GHG removal enhancements. While this instance could qualify for either scenario, the processes for addressing this issue in the Regulations are different with one using the forest buffer as a fall back option (intentional reversal) and the other not using the forest buffer account at all (invalidation). To avoid this inconsistency and likely future conflict in regulatory interpretation, TNC recommends that ARB utilize the same remedial process to address forest offset credit invalidation and intentional reversals. The forest buffer account should be used as security in instances where the OPO does not replace the invalidated or intentionally reversed forest offsets within 90 days. To ensure that the forest buffer account maintains sufficient offsets to remedy reversals and invalidation, ARB could adjust the forest buffer risk rating in the Forest Protocol (see Appendix D of the Compliance Offset Protocol for U.S. Forest Projects) to include invalidation risk. (NC8)

> **Response:** We do not agree that we should eliminate buyer liability associated with the invalidation of ARB offset credits. Requiring the user to replace the invalidated offsets ensures that purchasers and users of offset credits do their due diligence in seeking out high-quality offset credits. We have clear enforcement authority over covered entities that will be using ARB offsets for compliance. If the covered entity replaces any invalidated offset credits, they may then take appropriate action through third-party contractual arrangements that they may have established prior to purchase. These arrangements currently exist in the voluntary offset market, and we expect that as the offset market becomes more established, that additional mechanisms to deal with the risk of invalidation will also be established. In the event that the offset credit has not yet been used or retired, it will be canceled in the market tracking system and removed from any Holding or Compliance Accounts. These provisions in no way diminish our authority to assess penalties under section 96014 on any offset project developer or verifier that has provided false information to ARB.
>
> In addition, we made clarifications to both sections 95983 and 95985 to address stakeholder concerns that the regulatory language requires that offset credits be double compensated in the event of reversals. Section 95983(b)(2) now states that we will retire a quantity of ARB offset credits from the Forest Buffer Account in the event of an unintentional reversal. Sections 95983(c) and (d) specify that in the event of an intentional reversal the Forest Owner must replace ARB offset credits to ARB in the amount specified in the regulation. Also, in new section 95985(c)(4)(B) we specify that reversals do not constitute an invalidation, and if a reversal occurs, the provisions in section 95983 apply.

M-126. Comment: The provisions in section 95985 Invalidation of Offset Credits (b) should be modified. PacifiCorp recommends the inclusion of a materiality requirement for all provisions except for section 95985 (b)(2) The Offset Project Data Report contains errors that overstate the amount of GHG reductions or GHG removal enhancements by more than *5 percent.* Further, PacifiCorp recommends that section 95985(b)(4) include a provision that excludes the issuance of RECs from invalidating the offset credit. For example, if a dairy methane capture project, which qualifies as a carbon offset, burns the captured methane for electricity generation and the electricity generation qualifies for a REC, it should not invalidate the original offset (removal of methane from the atmosphere). (PACIFICOR3)

> **Response:** We included extensive modified provisions in section 95985 to make it clear what would trigger an invalidation, how we will invalidate offsets, and which offsets will need to be replaced. We believe that these changes provide clarity on this point. We have already clarified that biogas used for an

REC does not affect the digester project's ability to generate offset credits for destroyed or captured methane.

M-127. Comment: ARB should refine forest offset liability associated with invalidation and intentional reversals by identifying the Offset Project Operator as the party initially responsible for invalidation of forest offsets. According to sections 95983 and 95985 of Subarticle 13, the forest owner is responsible for replacing offsets whether it's due to invalidation or an intentional reversal. However, as stated previously, the forest owner is broadly defined to include any entity that has an interest in the property involved in the forest offset. The result of this broad definition creates significant uncertainty regarding who among the "forest owners" would be responsible for replacing offsets. The forest owner definition also states that only one entity who qualifies as a forest owner can be the Offset Project Operator. According to Subarticle 2, section 95802(a)(172), an "Offset Project Operator" is the "entity(ies) with legal authority to implement the offset project." If the Offset Project Operator (OPO) has the legal authority to implement the offset project and those who qualify as forest owners must identify only one OPO, it would be consistent and more clear to identify the OPO as the party, at least initially, who would be responsible to replace forest offsets in the event of forest offset invalidation and intentional reversals. ARB could also include a separate provision as it does in section 95985(h) that retains the authority of California to pursue enforcement action against any party in violation of the article. Doing so would provide more certainty to forest owners, market participants and regulated entities regarding the chain of liability that ARB would seek in an enforcement action and allow these parties to more thoughtfully address these risks in contracts. (NC8)

> **Response:** We do not agree that the Offset Project Operator should be liable for forest offset invalidations instead of the Forest Owners. We have enforcement authority over all forest owners under the regulation; however, identifying one party as the Offset Project Operator will be more administratively simple for both ARB and the forest owners when dealing with the various offset processes. At least one forest owner will be identified as the offset project operator. Forest owners have physical custody of the carbon stocks and therefore should have liability for the offset projects. The Forest Owners can establish contractual arrangements among themselves for establishing specific responsibility for invalidated credits.

Clarification of Reversals and Invalidation

M-128. (multiple comments)
Comment: Additional clarification about the relationship between intentional forest reversals and offset invalidation would be helpful. (TWS)

Comment: We are confused by the discontinuities between the forestry intentional reversals language and the invalidation provision regarding forestry. As written, the invalidation provision states in section 95985(g) that the Forest Owner must replace any ARB offset credit if it is found to be invalid pursuant to section 95985(b) and (d), and states that failure to do so will be considered a violation pursuant to section 96014. However, it is unclear whether section 95985(g) also incorporates section 95983(c)(3) and gives ARB to the authority to retire credits from the forestry buffer account if there is an invalidation of credits for reasons other than an unintentional or intentional reversal, or if ARB's sole recourse is to the forest owner to replace such credits. CERP requests clarification on this issue. (CERP4)

Comment: CMTA believes it is unreasonable and counterproductive to impose liability for intentional or unintentional offset reversals. The enforcement and potential penalty assessment of such liability ignores the purpose of the certification process. Since CARB has assured quality offsets through stringent offset qualification rules and third party verification, it is redundant and unreasonably onerous for the entity purchasing or surrendering the offset credit to also be responsible for it being real, permanent, etc. Allowing CARB to invalidate offsets eight years from the time they are issued will create unnecessary uncertainty and risk that could suppress the market. There is not substantial evidence in the record to justify the need for buyer liability to protect the integrity of the offset market. (CMTA3)

Comment: section 95985. Invalidation of ARB Offset Credits. The Regulation places the liability for invalidation due to errors and omissions made by unrelated third parties, such as verifiers, registries and software providers, on Forest Owners (including easement holders with no control over the project). This unknowable liability for multiple parties for incidents beyond their control will prevent many forestry projects from participating in the ARB program, especially those operated by small landowners. We therefore recommend ARB adopt a buffer pool approach to manage the risk of invalidation. If the current approach is maintained, Owner liability should be restricted to errors and omissions under their control, but leave liability for unintentional good-faith errors to a buffer pool or contributions from future verifications. (BLUESOURCE2)

> **Response:** We agree and made clarifications to both sections 95983 and 95985 to address stakeholder concerns that the regulatory language requires that offset credits be double-compensated in the event of reversals. Section 95983(b)(2) now states that we will retire a quantity of ARB offset credits from the Forest Buffer Account in the event of an unintentional reversal. Sections 95983(c) and (d) specify that in the event of an intentional reversal the Forest Owner must replace ARB offset credits to ARB in the amount specified in the regulation. Also, in new section 95985(c)(4)(B) we specify that reversals do not constitute an invalidation, and if a reversal occurs, the provisions in section 95983 apply.

Reversals in the Forest Sector

M-129. Comment: For unintentional forest reversals, ARB will retire credits from a 'Forest Buffer Account.' In the case of intentional forest reversals, a forest owner must provide a replacement offset or other compliance instrument or ARB will retire credits from Forest Buffer Account and commence an enforcement action against the forest owner. It is unclear what mechanism, if any, exists for replenishing the Forest Buffer

Account. ARB should make explicit any mechanism by which an enforcement action in the case of an intentional reversal will result in replenishment of the Forest Buffer Account and if any process exists for replacing retired Forest Buffer Account credits in the case of unintentional reversals. If no process exists for replacing Forest Buffer Account credits, or even if the Forest Buffer Account is only replenished in the case of intentional reversals, depletion of the Forest Buffer Account is a concern. If the Forest Buffer Account is depleted and unable to help restore tons to the Cap and Trade system that are lost due to reversals, then the integrity of the cap may be compromised. (TWS)

> **Response:** The regulation requires that the Forest Owner replace the reversed tons to the Forest Buffer Account. If they do not, there will be financial penalties that will apply. The replenishment of offset credits in the Forest Buffer Account is derived from a portion of offset credits issued to forestry projects. We believe the amount of offset credits received from forestry projects will sustain the Forest Buffer Account from retirement of offset credits due to unintentional or intentional reversals.

M-130. Comment: As with the quantification of intentional reversals from forestry projects in section 95983(c)(3), project owners should have one year to complete another verification and 90 days to replace the number of credits which were found to have been issued in error. If this can be applied to forestry projects, we believe similar latitude can be, and should be, applied to livestock offset projects. (CIG2)

> **Response:** We agree and allow Forest Owners to re-verify their forest projects within one year of the intentional reversals. In addition, we modified the regulation to give the Forest Owner six months to replace the reversed tons. In the case that ARB offset credits issued to livestock projects are invalidated pursuant to section 95985 the operator also has six months to replace the invalid ARB offset credits.

Permanence

M-131. Comment: CAR's reversal compensation rule for improved forest management projects (and in effect the same rule ARB is adopting in section 95983(c)(3)) is unnecessarily punitive for true working forest projects that do not choose to fully incur the incredible opportunity costs of sacrificing timber values and strongly disincentivizes forestland owners to concurrently improve forest management and supply legitimate offsets to the market. If compensation of reversals continues to be a requirement, as opposed to the VCS method of canceling credits from the buffer pool equal to the reversal, reversal compensation should be limited to the credits issued prior to the reversal. Such a rule would significantly improve the appeal of engaging in the CA offset market to forestland owners holding less than 1,000 acres because they wouldn't be penalized for occasional silvicultural activities that temporarily push above-ground standing live carbon stocks below the minimum baseline level (MBL). This potential change in reversal compensation would also preserve the relevance of conservation easements because the protocol wouldn't necessarily induce the level of conservation practices that are already incentivized by payments from land conservancies. Such compensation on top of what a landowner would commit to for carbon value would make participation in the California offset market even more financially rewarding, thereby facilitating increased landowner engagement. I recommend that ARB change the reversal compensation rule accordingly, and adopt the VCS Program requirements for the development of Agriculture, Forestry and Other Land Use (AFOLU) projects and methodologies found in sections 3.6.7, 3.6.8, and 3.6.11 as follows:

3.6.7 Where an event occurs that is likely to qualify as a loss event and VCUs have been previously issued, the following applies:
2) At the verification event subsequent to the loss event, the monitoring report shall restate the loss from the loss event and calculate the net GHG benefit from the monitoring period in accordance with section 4.7.2 and the methodology applied. In addition the following applies:
a) Where the net GHG benefit of the project, compared to the baseline, for the monitoring period is negative, taking into account project emissions, removals and leakage, a reversal has occurred and buffer credits equivalent to the reversal shall be cancelled from the AFOLU pooled buffer account as follows:
3.6.8 At a verification event, where a reversal has occurred, the following applies:
2) Where the reversal is a non-catastrophic reversal (eg, due to poor management or over-harvesting) the following applies:
a) No further VCUs shall be issued to the project until the deficit is remedied. The deficit is equivalent to the full amount of the reversal, including GHG emissions from losses to project and baseline carbon stocks.
3.6.11 Although buffer credits are cancelled to cover carbon known, or believed to be lost, the VCUs already issued to projects that subsequently fail are not cancelled and do not have to be "paid back." (GRINNELL)

> **Response:** To ensure permanence of GHG reductions and GHG removals we will manage the risk of reversals through the Forest Buffer Account. We believe this mechanism provides enough flexibility for developers of forest offset projects to manage the risk of potential reversals, and we do not see a need for additional mechanisms within the regulation.

Early Action

Early Action Operations

M-132. Comment: PG&E supports the modifications to the Early Action Offset section of the Regulations. These modifications will encourage existing projects to transition to the ARB Compliance Protocols. These projects are critical to address the expected shortage of offset credits early in the program. (PGE4)

> **Response:** Thank you for your support on the modifications to the regulation.

M-133. Comment: We are not sure why a project developer is not allowed to use ARB protocols to register new projects in 2012. To us, using ARB protocols from 2012 would greatly simplify and harmonize registration. It would provide an opportunity to "road-test" these protocols and the ARB issuance process. Again, requiring projects to effectively undergo two verifications (one for CAR and another for ARB) has a disproportionate impact on smaller-scale projects and increases uncertainty for small-scale developers. For example, the price differential, showing the uncertainty over the ARB re-verification process, at the moment between CAR livestock CRTs and ARB offsets is around $3, or 25-30 percent. (CIG2)

> **Response:** The regulation includes provisions to allow early action offset credits to be credited as ARB offset credits and used in the cap-and-trade program. We included these provisions to allow parties to develop offset projects and purchase offset credits that are being issued by Early Action Offset Programs. These provisions will provide parties with certainty that the regulation will allow them to participate in the offsets market while we finalize the regulation and take the necessary implementation steps to develop a fully functioning ARB offsets program and offsets tracking system. Once ARB Compliance Offset Protocols are finalized, project developers will be able to use them to quantify, monitor, and report their GHG reductions and GHG removal enhancements. In 2012, we will approve additional Offset Project Registries so that project developers can list and report their emissions with these registries. We will also accredit ARB offset verifiers to verify GHG reductions and GHG removal enhancements from offset projects developed under Compliance Offset Protocols.
>
> In addition, we added new section 95990(k) to the regulation to clarify how early action offset projects transition to Compliance Offset Protocols.

M-134. (multiple comments)
Comment: Section 95990(i) states that section 95985 applies to entities submitting Early Action Offset Credits for ARB Offsets. It also contains language which states the entity which submits the EAOCs for ARB Offsets is liable in the event an offset is invalidated and the end-user is no longer in business. For forest owners who submit EAOCs, this language directly conflicts with section 95985(g). We recommend that ARB clarify this section so that the language in this section is specific for Holders of EAOCs while the language in 95985(f) and (g) is referenced for the Offset Project Operator, Offset Project Designee, or Forest Owner if applicable if one of these is the entity which submits the EAOCs for ARB Offsets. (FINITE)

Comment: Page A-265 (1) Transfer of Early Action Offset Credits to ARB by Credit Holders vs. Project Operators. While we support the ability of Holders of Early Action Offset Credits to submit credits for listing, pay for verification and receive issued ARB offsets independently of the Forest Project Operator, the Operator's immediate and long term roles remain unclear in the current draft of the Regulation. We request that it be made clear that Project Operators who have sold Early Action Offset Credits under CAR that are subsequently independently submitted to ARB by third party Holders, are not subject to any associated liabilities for Reversal and Invalidation. (BLUESOURCE2)

Comment: Clarify in sections 95990(l) and 95990(f)(3)(E)) where an Early Action forestry offset holder that chooses to transition their issued offsets to ARB but the forest owner and/or Offset Project Operator choose not to transition the entire project, whether the invalidation risk would be borne by the forest owner or the Early Action offset holder who transitioned the offsets to ARB. Please note that in many cases the Early Action offset holder has no contractual link to the forest owner and may not be able to compel the forest owner to transition their project to ARB. (CE2CC)

> **Response:** We modified section 95990(l), which now deals with invalidation, to clarify the invalidation provisions related to early action offset credits. The requirements are that for non-sequestration projects the party that surrendered the offsets must replace them. If they are no longer in business, it is the party that brought the offsets into the system. This could be the project developer or the current holder of the CRTs. For forest projects, the forest owner must replace them. We believe these clarifications address the commenter's concerns.

M-135. Comment: Section 95990 allows holders of Early Action Offset Credits to submit projects for listing, pay for verifications, receive issued ARB offsets, and requires them to provide attestations binding them to comply with the Regulation. We commend ARB for including this option and recognize its necessity during the program through 2014. We request that ARB make it explicit that project owners who have sold Early Action Offset Credits and subsequently have those offsets submitted to ARB by holders of Early Action Offset Credits are not subject to the liabilities associated with such credits under ARB, specifically in regard to sections 95983 and 95985 (specifically as it pertains to forest owners). (FINITE)

> **Response:** We modified section 95990(l), which now deals with invalidation, to clarify the invalidation provisions related to early action offset credits. The requirements are that for non-sequestration projects the party that surrendered the offsets must replace them. If they are no longer in business, it is the party that brought the offsets into the system. This could be the project developer or the current holder of the CRTs. For forest projects, the forest owner must replace them. We believe these clarifications address the commenter's concerns.
>
> If the party that surrendered the offsets does not replace them, we have the authority to enforce against the party that brought them into the system. These provisions ensure our enforcement authority and the integrity of the program. We did not eliminate the attestation requirements; however, we did make minor modifications to the wording of the attestations. These attestations are necessary to ensure our enforcement authority and the integrity of the system.

M-136. Comment: While IETA understands that sections 95990(h)(5)(A), (B), and (C) relate to ARB attempting to apply its buyer liability rule to early action offset credits, holders of early action offsets cannot make the attestations outlined in (A) and (C), as these elements are beyond their control and fall, instead, under the purview of the original project verifier and ARB appointed verifier. IETA strongly recommends these attestations not be required of the project operator, designee, or holder of the early action offset credit seeking issuance. They are an additional administrative burden that may prevent holders of early action credit from seeking issuance, ultimately discouraging participation and disrupting supply. If ARB insists on a buyer liability approach, despite IETA's recommendations and proposed solutions in the previous section, then it will presumably apply to early action offset credits as well and should not warrant a requirement to make the above attestations on the part of project owners, designees, and holders. (IETA3)

> **Response:** We modified section 95990(l), which now deals with invalidation, to clarify the invalidation provisions related to early action offset credits. The requirements are that for non-sequestration projects the party that surrendered the offsets must replace them. If they are no longer in business, it is the party that brought the offsets into the system. This could be the project developer or the current holder of the CRTs. For forest projects, the forest owner must replace them. We believe these clarifications address the commenter's concerns.
>
> If the party that surrendered the offsets does not replace them, we have the authority to enforce against the party that brought them into the system. These provisions ensure our enforcement authority and the integrity of the program.

M-137. Comment: The OWG is highly supportive of ARB's inclusion of early action offsets within the cap-and-trade program. In order for projects to qualify for early action credit, the OPO must carefully follow the proper steps for listing, verification, issuance, and registration. The regulations also have requirements for transitioning early action offset projects into ARB offset projects. The OWG requests ARB to hold at least one stakeholder workshop to explain the entire process in a clear and concise manner. This workshop should be held very soon as OPO's are already contemplating structuring their projects to produce these early action offset credits. If the record is re-opened for a second round of 15-Day comments, the workshop should be held in advance of this period. (OFFSETSWG3)

> **Response:** Thank you for your comment. We will consider holding a workshop on the details of the offset program once the rulemaking process is completed. In addition, we will develop guidance documents as necessary regarding specific aspects of the offsets program.

M-138. Comment: Section 95990(j)(1) and (2) of the proposed revised Regulations appear to require that all holders of early action credits from a particular project must register in order for ARB to issue ARB Early Action Credits for the project. This language is problematic because some holders of credits from a project listed under a non-ARB offset project registry have no intention of exchanging early action credits for ARB Early Action Credits. Yet, these entities would be required to register and prove ownership of such credits in order for any holders to receive ARB Early Action Credits. ARB staff have told CERP members that their intention is that only those holders that wish to transition their credits should have to register. Modify section 95990(j) as follows:

> (j) Registration and Transfer of ARB Offset Credits for Purposes of Early Action. An ARB offset credit issued pursuant to section 95990(i) will be registered by creating a unique ARB serial number. ARB will transfer the serial numbers into the Holding Account of ~~the~~ a holders of the original early action offset credit within 15 working days of the notice of issuance pursuant to section 95990(i)(4), unless otherwise required in section 95990(i)(1)(D), and as long as the holders meets the following requirements
>
> (1) ~~All~~ The holders of the original early action offset credits registers with ARB pursuant to section 95830; and
>
> (2) ~~All~~ The holders of the original early action offset credit~~s~~ proves ownership of ~~those~~ the offset credit~~s~~, including original serial numbers issued by the Early Action Offset Program. (CERP4)
>
> **Response:** We agree that the requirements as written were confusing and clarified the language in this section.

Early Action Offset Supply and New Early Action Protocols

M-139. (multiple comments)
Comment: The OWG is concerned that with just four approved compliance offset protocols and the opportunity for some Early Action Offsets there will still not be adequate supply of offsets in the market, particularly in the early years. The OWG, therefore, urges ARB to expeditiously consider and adopt new compliance offset protocols. The OWG believes that a variety of protocols that have been developed in the market can be fairly quickly adopted as compliance protocols. (OFFSETSWG3)

Comment: VCSA notes that, with the exception of the placeholder language in section 95990 regarding early action offsets, the modified draft rule still limits the number of offset protocols eligible for use in the California cap and trade program to the four project types already approved. Such a limitation places an unnecessary constraint on the market, stifling innovation, creating uncertainty among project developers and investors, and ultimately limiting the cost containment benefits that offsets offer to a cap and trade system. There exist a number of established carbon offset standards that have significant standing in the domestic and international carbon markets that stand as ready sources of protocols for ARB's consideration. ARB should initiate an open, transparent process for evaluating and approving protocols from established, high quality carbon offset standards prior to the 2013 implementation of the cap and trade program. (VCSA)

Comment: Evolution Markets encourages ARB to adopt additional early action offset project protocols as expeditiously as possible to ensure adequate offsets are available at the outset of the program, as well as sufficient market liquidity. Short of ARB adopting additional protocols in 2011, Evolution Markets strongly recommends ARB provide a short list of project types and standards that have been reviewed and are a priority for adoption. (EVMKTS2)

Comment: VCSA is pleased to see that the criteria for approval of early action offset credits issued by early action offset programs (section 95990 (c)) now includes a place holder for GHG reductions or enhancements that result from the use of “additional early action offset project protocols” (i.e., protocols other than the four protocols already approved by ARB) (95990(c)(5)(E)). Expanding the list of eligible protocols will encourage more projects to seek credit for early action and, as a consequence, will enhance liquidity and help contain the cost of compliance early in the program. This is especially important given the possibility that the supply of offset credits issued under the four approved protocols may not meet demand. The modified draft rule, however, does not identify a mechanism for how additional protocols will be considered and added to the list of existing eligible early action methodologies. To truly facilitate the development of an adequate pool of early action credits, more clarity must be provided for how early action protocols can be brought forward for consideration and approval. Amend section 95990 to include a provision that describes a transparent process that ARB will employ to consider, evaluate and approve additional early action offset protocols. (VCSA)

Comment: CERP encourages ARB to expand early action eligibility beyond the four currently approved Climate Action Reserve (CAR) protocols to substantially similar voluntary protocols from other well-established project registries. (CERP4)

Comment: The GHG Early Action Group holds approximately half a million tonnes of GHG reductions, primarily from Ozone Depleting Substances as defined by ARB. These entities hold credits issued for ODS destruction and livestock methane destruction from the Chicago Climate Exchange (CCX). These credits were issued by the CCX under quantification rules and requirements nearly identical to those in the ARB protocols for ODS destruction and livestock methane destruction. Though these credits were issued under protocols which are substantially equivalent as two of the methods recognized by ARB, were developed using public participation procedures, and even though some of the project represented here have "migrated" to the Climate Action Reserve, the credits which are the subject of this comment are not susceptible to transfer. These credits remain valid and ought to be recognized. At the same time, while the CCX has advised that it has in place each of the requirements for an Early Action Offset Program in 95990(a) with respect to these credits, the CCX may or may not be continuing to issue credits. Given the proposed language of 95990(a), there is some question as to whether the CCX would be eligible. (GEAG)

Comment: Since ARB may in the future approve additional early action offset project protocols, as noted in the new section 95990(c)(5)(E), ACR suggests adding section 95990(i)(1)(F), <u>"Reserved for additional early action offset project protocols approved under section 95990(c)(5)."</u> (MARTINN3)

Comment: ACR suggests adding, section 95990(k)(1)(F), "Reserved for additional early action offset project protocols approved under section 95990(c)(5)." (MARTINN3)

> **Response:** In regard to additional early action offset protocols, this comment falls outside the scope of the First 15-Day Changes Notice. Because the comment falls outside the scope of the notice, no further response is required. Responses to similar comments can be found in this category under the 45-day comment responses.

M-140. Comment: PG&E supports the addition of section 95990(c)(5)(E) which would allow for the inclusion of additional early action offset project protocols. The inclusion of additional early action offset project protocols will help address PG&E's concerns regarding the expected shortage of offset credits early in the program. (PGE4)

> **Response:** Thank you for your support on the modifications to the regulation.

Early Action Offset Project Eligibility

M-141. Comment: Page A-271 (D)(2) Potential Double Buffer. If CAR or another registry is unwilling to transfer buffer pool credits to ARB, the project or credit owner would need to submit an equivalent number of credits to the ARB buffer pool. This has no scientific basis as the risk is unchanged. It imposes an unfair burden on the landowner when the maintenance of a buffer mechanism equivalent to that of ARB should be the responsibility of the ARB Early Action Offset Program. (BLUESOURCE2)

> **Response:** We added a requirement in section 95990(i)(1)(D)(1.) that the Early Action Offset Program transfer all offsets that reside in their buffer account for forestry to ARB, so that we may ensure permanence of any offset project in the ARB compliance program. Once the early action offset credits are verified pursuant to section 95990(f) and meet the requirements for early action we will issue ARB offset credits to replace the early action offset credits, and the Early Action Offset Program must permanently remove them from their registry system. This clarifies that we have full control over the offset credits that are issued, even for early action purposes, and the Forest Buffer Account. These additional requirements should alleviate concerns that the Forest Owner must replace reversed tons in both programs.

M-142. Comment: Section 95973 states early offsets can include offsets before December 31, 2006. Is there an estimate (or limit) on the number of these early offsets that can be allowed? This recognizes very old offset projects, and could diminish onsite reductions from covered entities. (SCAQMD4)

> **Response:** We expect the number of offsets with vintages prior to December 31, 2006, to be a very low percentage of the overall number of offsets allowed into the system. The only offsets that are eligible prior to this date are GHG reductions or GHG removal enhancements that occurred in 2005 or 2006. We do not believe that this will diminish on site reductions from covered entities. The program imposes a limit on what we believe is an appropriate amount of offsets that an individual covered entity can use for compliance. All offsets used for compliance are real reductions, albeit outside the cap. Allowing a limited number of offsets into the program provides cost-containment benefits and ensures that some GHG emissions reductions occur within the sectors covered by the cap-and-trade program. The program includes provisions that would allow a maximum of 201 $MMTCO_2e$ of offsets through the year 2020. This limit will be enforced through a limit on the use of offsets by an individual entity equal to eight percent of its compliance obligation. Combined with the Allowance Price Containment Reserve, this limit ensures that a majority of reductions from the program come from sources covered by the program at expected allowance prices, while use of the reserve will relax that constraint if prices rise.

M-143. (multiple comments)
Comment: Page A-264 (c)(1) Compliance Vintages. The Regulation limits early-action compliance vintages to 2005-2014. The justification for the earliest vintage to be 2005 is that it was the first year Climate Action Reserve offset protocols were available for verification. We recommend that ARB revise the early action vintage date to 2001, which corresponds to the signature of California Senate Bill No. 527. This would justify start date based on a landmark California legislative precedent (not a private administrative procedure) as well as align with CARs own rationale for allowing projects to 2001. (BLUESOURCE2)

Comment: Section 95990(c)(1) limits early-action compliance vintages to 2005-2014. The justification for the earliest vintage to be 2005 is that it is the first year Climate Action Reserve offset protocols were available for verification. This justification is problematic. First, although it was the first year the Climate Action Reserve protocols were available for verification, there is nothing in the ARB Regulation which limits early-action criteria to Climate Action Reserve projects only. Another registry which may be approved by ARB may have had its first protocol available for registration in 2002 or 2004 or any of a number of dates. Second, while 2005 is the year in which the protocols were first available to be used for verifications, the Climate Action Reserve Protocols allow for projects to receive verified CRTs as far back as 2001. Third, the early action criteria do not have a cut-off for early start dates. Therefore, a project may start in 2001 but its 2001-2004 vintages would not be considered compliance-grade while its 2005 vintages are. There is no scientific or policy reason that a 2004 vintage offset and a 2005 vintage offset from the same project do not constitute equal quality emissions reductions. Forest carbon projects in particular are adversely impacted by this provision. Forest carbon offset projects tend to have a significant number of offset credits issued in the first year of the project with annual offsets issued to a much lesser extent. If a project were to have a start date of 2001, the majority of the project offsets would come at that time. If 2001 vintages are excluded as compliance offsets, they will lose significant value in the market and make it difficult if not impossible for the project to pay for the 100+ year compliance costs let alone the opportunity cost for foregone harvest. Of the 72 forest carbon projects listed or registered on the Climate Action Reserve, 29 have pre-2005 start dates. We recommend that ARB revise the early action vintage date to 2001 which corresponds to the signature of SB 527 so that the justification is rooted in a California precedent and is not specific to an independent registry which may be one of many ultimately approved. (FINITE)

> **Response:** This comment falls outside the scope of the First 15-Day Changes Notice. Because the comment falls outside the scope of the notice, no further response is required. Responses to similar comments can be found in this category under the 45-day comment responses.

Early Action Offset Project Transition

M-144. (multiple comments)
Comment: Transitioning an early action project to ARB's Forest Project Protocol (FPP), section 95990(k)(3)(C), requires that the project be listed with ARB or an Offset Project Registry by February 28, 2015. Early action forestry projects will most likely not have completed the verification of their 2014 offsets by that date. To eliminate potential inconsistencies between the listing requirements for transition to the ARB FPP and the requirements for verifying early action project offsets under FPPv.2.1, modify section 95990(k)(3)(C) as follows:

(C) To transition an early action offset project to the ARB compliance offset program, the offset project must be listed with ARB or an Offset Project Registry by ~~February 28, 2015~~ <u>June 30, 2015</u>. (TCF2)

Comment: PG&E appreciates the addition of section 95990(k), which requires projects to transition to the ARB protocol no later than February 28, 2015. It is PG&E's assumption that, because the Climate Action Reserve protocols listed in section 95990(c)(5) do not specify a timeframe for the annual verification, an Early Action Offset Project has "nine months after the conclusion of each Reporting Period" to verify its 2014 offset credits consistent with section 95977(d). Therefore, an Early Action Offset Project "must be listed with ARB or an Offset Project Registry by February 28, 2015" (section 95990(k)(3)(C)), but has until September 30, 2015 to complete the verification of its 2014 offset credits. (PGE4)

Comment: CERP seeks clarification about the timeframe for transitioning. The ambiguity arises because the Climate Action Reserve protocols listed in section 95990(c)(5) do not specify a timeframe for the annual verification. Accordingly, we request clarification that an Early Action Offset Project has "nine months after the conclusion of each Reporting Period" to verify its 2014 offset credits, which is consistent with the time period for verification in section 95977(d). If this is correct, an Early Action Offset Project "must be listed with ARB or an Offset Project Registry by February 28, 2105" (section 95990(k)(3)(C)), but has until September 30, 2015 to complete the verification of its 2014 offset credits. This additional time will especially important for forestry 2.1 projects that are required to recalculate their baselines prior to transitioning. (CERP4)

> **Response:** We modified section 95990(k)(3)(C) to allow GHG reductions and GHG removal enhancements that occur in 2014 under an early action protocol to be verified by September 30, 2015. This change was made in response to stakeholder comments that we should streamline the requirements for early action offset projects with those for offset projects using Compliance Offset Protocols by allowing early action offset projects to have nine months to verify their Early Action Data Report.

M-145. (multiple comments)
Comment: Section 95990(k)(3) allows projects to re-start their crediting period when they transition to a Compliance Offset Protocol. However, when an offset is no longer an early action offset, we are not sure that 95973(a)(1)(b) still applies. We request that ARB clarify that early action projects which have start dates prior to December 2006 will be able to transition to the Compliance Offset Protocol. (CIG2)

Comment: The OWG recommends greater clarity in this Section by removing the second sentence in Section 95973(a)(2) from that paragraph. As it stands, the sentence implies that the items in (A) through (C) are for Early Action Offset Protocols, rather than Compliance Offset Protocols as intended. In addition to the deletion in 95973(a)(2), the core component of the sentence should be re-inserted into Section 95973(c) as follows:

(a)(2) Meets the following additionality requirements, as well as any additionality requirements in the applicable Compliance Offset Protocol, as of the date of Offset Project Commencement. ~~Early action offset projects which transition to the compliance offset program pursuant to section 95990(k) must meet the requirements of that section:~~

(c) Early Action Offset Project Commencement Date. Offset projects that transition to Compliance Offset Protocols pursuant to section 95990(k) must meet the requirements of that section. These projects may have an Offset Project Commencement date before December 31, 2006. (OFFSETSWG3)

Comment: The last sentence in section 95973(a)(2) implies that the items in (A) through (C) are for Early Action Offset Protocols, rather than Compliance Offset Protocols which is what PG&E believes was intended. We recommend that the sentence “Early action offset projects which transition to the compliance offset program pursuant to section 95990(k) must meet the requirements of that section” should be added as a new item under section (a). (PGE4)

Response: We modified the language in section 95973 to make it clear that early action offset projects may have a start date prior to December 31, 2006.

M-146. Comment: Early action projects have an effective crediting period of ten years (2005 through 2014). For forest sequestration projects, this relatively short crediting period may be insufficient to induce an early action forest project developer to submit to ARB's jurisdiction and enforcement authority for 100 years. The transition of an early action project to the ARB FPP pursuant to section 95990 provides an opportunity for an early action project to establish the longer crediting period contemplated in section 95972(b) (as well as the opportunity for unlimited renewals as set forth in 95975(k)(1)). The opportunity to transition to the ARB FPP and gain a longer crediting period is a powerful incentive for early action projects to participate in the compliance program. However, we are concerned that the ARB FPP may change in material respects after we enter our projects into the compliance program but before we complete the transition, most likely in early 2015. To address this uncertainty, modify section 95990(k)(1)(D) as follows:

(D) Early action offset projects using Climate Action Reserve Forest Project Protocol version 2.1 must use and meet all the requirements in Compliance Offset Project U.S. Forest Projects <u>in effect on the date ARB offset credits are issued to the project pursuant to 95990(i)</u>. At the time of transition the early action offset project must calculate its project based according to all the provisions in Compliance Offset Protocol U.S. Forest Projects, [DATE] and the requirements in this article from the date of offset project commencement under the Early Action Offset Program to the date the early action offset project applies for transition pursuant to section 95990(k). This project baseline will remain valid for the duration of the offset project life. (TCF2)

Response: New section 95990(k) was added to clarify how early action offset projects transition to Compliance Offset Protocols. New section 95990(k)(2) clarifies that once an early action offset project transitions to a Compliance Offset Protocol it will begin an initial crediting period. The crediting period under the early action offset program does not count under the compliance offset program, so the early action offset project may transition to a Compliance Offset Protocol any time before February 28, 2015, but must list or register with an Early Action Offset Program by January 1, 2014 (section 95990(c)(3)). We removed any requirements that restrict the earliest date that early action offset projects must transition to Compliance Offset Protocols. It is necessary for offset projects beginning February 28, 2015, to transition to Compliance Offset Protocols to ensure consistency in the program and that all offset projects are following the rules of the regulation, including the rules in the Compliance Offset Protocols.

M-147. (multiple comments)
Comment: Page A-274 (k)(1) Transition of Early Action Projects to Compliance Program. Early Action Projects' inability to transition to ARB before 1/1/13 seems

arbitrary and problematic. This unnecessary restriction will limit the supply of offsets to the ARB program at its outset and impose unnecessary costs on landowners who must verify 2011-12 credits under both CAR and ARB programs. We therefore recommend ARB allow projects to transition to the ARB Compliance Offset Protocols as soon as these protocols and associated verification infrastructure are available. (BLUESOURCE2)

Comment: Section 95990(k)(1) does not allow projects to transfer to ARB Compliance Offset Protocols until after January 1, 2013. There is no reason to prevent projects from transferring to the Compliance Protocols as soon as these protocols are available. Many projects are only registering with Early Action Offset Programs because they have no other option. By forcing a project to remain under an Early Action Offset Program until after 2013, a project will face double verification costs (once under the EAOP and another under ARB) which could add up to $35,000 in unnecessary duplicative verification costs. We recommend ARB delete this requirement and allow projects to transition to the ARB Compliance Offset Protocols as soon as these protocols are available. (FINITE)

> **Response:** We agree and removed the requirement that a project may not transition prior to 2013. New section 95990(k) was added to clarify how early action offset projects transition to Compliance Offset Protocols. The early action offset project may transition to a Compliance Offset Protocol any time before February 28, 2015, but must list or register with an Early Action Offset Program by January 1, 2014 (section 95990(c)(3)).

M-148. Comment: Because offset projects cannot transfer registration to the ARB prior to 2013, we expect many projects will submit re-verified credits to the ARB for transfer on more than one occasion. For example, a project developer may submit all credits through vintage 2011 during 2012, and then submit vintage 2012 credits during 2013. With this in mind, the proposed language is not clear as to the implications of the second (in our example, 2013) desk review on credits which have already been transferred to the ARB. Specifically, it is not clear whether credits which have already been transferred successfully and issued as ARB offsets must be re-reviewed (again) if any subsequent regulatory re-verification finds a material misstatement in a later vintage. We recommend that if an Early Action offset credit has successfully completed a desk review and has been converted to an ARB offset, that no further reviews or re-verifications be automatically triggered if a subsequent desk review of later vintages is found to require a full regulatory verification with site visit. That is to say, once an ARB offset credit has been issued from an Early Action offset credit, that ARB offset credit should not be subject to re-verification as a result of subsequent Early Action offset credit transfer activities. (TPI5)

> **Response:** We agree and removed the requirement that a project may not transition prior to 2013. New section 95990(k) was added to clarify how early action offset projects transition to Compliance Offset Protocols. The early action offset project may transition to a Compliance Offset Protocol any time before

February 28, 2015, but must list or register with an Early Action Offset Program by January 1, 2014 (section 95990(c)(3)).

We also added new section 95990(f)(7) which specifies that once an Offset Project Data Report has been reviewed and early action offset credits have been issued, it does not need to be re-reviewed if future data report years are verified according to section 95990(f).

M-149. (multiple comments)
Comment: Section 95973(c) allows projects with start dates prior to December 31, 2006 to register under the ARB Compliance Protocols provided that they transition from an Early Action Offset Program. In order for a forest project to transition from CAR to an ARB Compliance Protocol, the forest owner would have to terminate the Project Implementation Agreement (PIA) with CAR. CAR has a provision which may allow an owner to cancel the PIA in order to transition to a state or regional compliance program. However, if a project has a pre-2005 start date, the project will be unable to transfer 2001-2004 offsets to ARB as the Regulation currently stands. This will either result in forest owners being prevented from transitioning to the ARB Compliance Protocol or require the forest owner to pay a penalty to CAR for all 2001-2004 offsets issued in order to terminate the PIA. Of the 72 forest carbon projects listed or registered on the Climate Action Reserve, 29 have pre-2005 start dates. We recommend that ARB allow forest owners avoid this obstacle by allowing them to transfer 2001-2004 offsets to ARB's registry provided they are immediately retired (or allow them to be eligible for compliance use). (FINITE)

Comment: Page A-170 (c) Early Action Offset Project Commencement Date. Projects with pre-2005 start dates will be unable to transfer 2001-2004 offsets to ARB as the Regulation currently stands. However, in order to transfer credits into the ARB program a landowner would need to terminate its PIA with CAR. They would therefore need to purchase and return to CAR a number of 2001-2004 credits equivalent to the number that has previously been sold in the market. We recommend that ARB remove this obstacle by allowing landowners to transfer 2001-2004 offsets to the ARB program for buffer or other purposes. Approximately 40 percent of current CAR-listed forestry projects face this obstacle. (BLUESOURCE2)

Response: These comments relate to agreements having to do with voluntary greenhouse gas reduction projects, not the regulation. We were not involved with the voluntary program or any agreements it requires; therefore, we did not get involved in trying to resolve the types of issues presented in the comments.

M-150. Comment: Section 95990(i)(1)(D)(2) states that Buffer Account Credits may either come from the registry which issued the credits or be subtracted from the number of EAOCs submitted for ARB Offsets. This policy leaves the policy decision for transfer of Forest Buffer Account Credits from the Early Action Offset Program to ARB in the hands of the Early Action Offset Program. Since ARB has the capacity to create the terms under which an EAOP is accepted under the Regulation, it should require that an

EAOP must transfer any Forest Buffer Account Credits associated with EAOCs which are submitted for ARB Offsets. This would provide a more certain environment for project owners to submit early action forestry projects to EAOPs while awaiting the ability to submit directly under the ARB Compliance Offset Protocols. We recommend that ARB amend the language so that: "ARB offset credits placed into the Forest Buffer Account must come from a buffer account held by the Early Action Offset Program, if they are determined to meet the criteria of section 95990(h); or, if there are insufficient forest buffer account credits to meet the requirements of ARB, or subtract the difference between the available forest buffer account credits and the amount determined in section 95990(i)(1)(D)(1) from the total number of ARB offset credits issued pursuant to this section." (FINITE)

> **Response:** We added a requirement in section 95990(i)(1)(D)(1.) that the Early Action Offset Program transfer all offsets that reside in their buffer account for forestry to ARB, so that we may ensure permanence of any offset project in the ARB compliance program. We also included requirements in the regulation to subtract the difference between the buffer credits from the registry's buffer account and the amount determined to be due to ARB pursuant to Compliance Offset Protocol U.S. Forest Projects.

M-151. Comment: IETA recommends ARB provide additional clarification to the provisions dealing with the conversion of forestry offsets to ARB early action offset credits. For instance, IETA is unsure of the intent of section 95990(i)(E) and would like ARB to clarify its objectives under this section. (IETA3)

> **Response:** We agree that early action projects should have the option to transition to compliance offset projects, and made several modifications to the regulation to facilitate this process while still ensuring the integrity of the offsets. New section 95990(k) was added to clarify how early action offset projects transition to Compliance Offset Protocols. New section 95990(k)(2) clarifies that once an early action offset project transitions to a Compliance Offset Protocol it will begin an initial crediting period.
>
> The section you are referring to as 95990(i)(E) is now section 95990(k)(1)(E) of the regulation. This provision requires projects developed under CAR's forest protocol version 2.1 to recalculate their baseline based on ARB's Compliance Offset Protocol. This provision is necessary to ensure consistency across all forest projects in the compliance program. Early action offset projects developed under the other protocols mentioned in section 95990(c)(5) must transition to the appropriate Compliance Offset Protocol but do not need to change their baselines.

Transitioning Early Action Offset Credits to ARB Offset Credits

M-152. (multiple comments)
Comment: Section 95990(d) requires an Offset Project Operator or Authorized Project Designee for an early action offset project to register with ARB before ARB offset credits may be issued. This step should be modified to also allow holders, or owners, of early action offset credits to register with ARB in case there is no interest or incentive to do so on the part of project operators or authorized designees. (IETA3)

Comment: Clarify who may submit information or be identified under section 95990(e). As written, the only persons who can submit information under section 95990(e)(1) are "Offset Project Operator or Authorized Project Designee." Under section 95990(e)(2) the program only needs to list the same persons. The list of persons who may submit information under section 95990(e)(1) and who should be identified under section 95990(e)(2)(C) should be expanded to those who currently hold the offset credits, whether they be CFIs, CRTs, VCUs, or ERTs. As shown by the Members of the Early Action Offset Group, these early carbon credits do have value and have been sold. Whether now held by investors or potential end users, those persons too should be entitled to start the process for issuance of ARB offset credits in section 95990(e). (GEAG)

> **Response:** We made modifications to section 95990 to streamline the process for transitioning early action offset credits into ARB offset credits that can be used for compliance. This includes allowing holders/current owners of early action offset credits to transition them into the compliance program if the project developers do not do so in most cases.

M-153. (multiple comments)
Comment: ARB has proposed to modify the rules for creating early action offset credits to now include the process for converting early action credits into ARB-issued offsets. We welcome the intent of this proposed modification, though we are concerned that the process for accrediting early action credits and transitioning them to ARB-certified offsets is still too administratively burdensome. We propose a number of specific additional modifications to help ensure a smooth transition mechanism, and thus encourage more projects to seek credit for early action. This will help to ensure that more valid emission reductions are transferred from the voluntary market to California's compliance market, which is important given that ARB and most analysts currently predict that there will be a shortage of offsets in the early period. Our proposed minor modifications are listed below.

- Expand the scope of those that can register the early action credits. Section 95990(d) requires an Offset Project Operator or Authorized Project Designee for an early action offset project to register with ARB in order for compliance offset credits to be issued. We recommend that this be modified to allow holders of early action offset credits to register with ARB in case the project operators or authorized designees do not do so.

- Eliminate the Burdensome Attestation Requirements. Sections 95990(h)(5)(A), (B),and (C), require the Offset Project Operator, Authorized Project Designee, or each holder of the early action credit seeking issuance of ARB offset credits to attest in writing that (A) the reductions/removals have been measured in accordance with the appropriate early action offset protocol and that all information submitted to ARB is true, accurate and complete; (B) its participation in the Program is voluntary and subject to ARB's regulatory requirements and subject to ARB's exclusive jurisdiction to resolve any and all disputes; and (C) it acknowledges the need to fulfill all applicable local, regional, and national regulatory requirements that apply to the offset project—in essence, attesting to the offset project's regulatory additionality. We have no objection to the second of these, subsection (h)(5)(B), provided that it can be extended to any holder a credit that may seek to register it per our first proposed modification. However, the other two attestations, subsections (h)(5)(A) and (C), are properly within the purview of the verifiers. We respectfully recommend that these attestations not be required of the project operator, designee, or holder of the early action offset credit seeking to register them with ARB as compliance offset credits. (COPC3)

Comment: The Trust has concerns that the process for accrediting early action credits and transitioning them to ARB certified offset credits remains burdensome and confusing. Procedures for transitioning early action offset credits need tightening and clarification. In particular Section 95990(d) should be modified to allow holders or owners of early action credits to register with ARB in addition to Offset Project Operators and Authorized Project Designee. Sections 95990(h) (5) (A), (B) and (C) should be tailored more narrowly to the statements each of these entities would be competent to make about the status of projects and credits. For example, an Authorized Project Designee may not be able to attest to how the credits were measured since this is the responsibility of the verifier.

A smoothly functioning system that takes into account the realities of the state of the carbon market, and the fact that the credits have already been verified, will reduce the uncertainty around the transfer of Climate Action Reserve Tonnes. This is necessary to ensure that more projects seek credit for early action and to enhance liquidity early in the compliance periods, thereby reducing the costs of the program. (TCT)

> **Response:** We made modifications to section 95990 to streamline the process for transitioning early action offset credits into ARB offset credits that can be used for compliance. This includes allowing holders/current owners of early action offset credits to transition them into the compliance program if the project developers do not do so in most cases. We did not eliminate the attestation requirements; however, we did make minor modifications to the wording of the attestations. These attestations are necessary to ensure our enforcement authority and the integrity of the system.

M-154. Comment: CERP respectfully requests that ARB streamline the listing process of an early action project. Section 95990(e) suggests that offset project operators for early action projects will have to go through the entire listing and information submission process that would apply for a "compliance" offsets project. CERP believes that this adds needless costs, especially given that the Climate Action Reserve and other registries already require much of the same information and require that such information be made public. A shorter listing process, such as a form on which the Offset Project Operator or Designee could provide basic information about the project and the vintages and volumes to be transferred, could provide sufficient information for early action projects while maintaining environmental integrity. It also would help speed implementation by ARB. (CERP4)

> **Response:** We did not make these changes. This information is needed for transparency purposes.

M-155. Comment: IETA notes that ARB has modified its rules for creating early action offset credits to now include the process for converting early action credits into ARB-issued offsets. While IETA is pleased to see ARB recognize early actors that have invested in low-carbon and clean technology projects, IETA has concerns the process for accrediting early action credits and transitioning them to ARB-certified offsets is still too administratively burdensome. A smooth and simple transition mechanism will facilitate the process, encourage more projects to seek credit for early action, and reduce uncertainty on the transferability of Climate Reserve Tons and offset credits issued under other qualifying programs. Such a program will also enhance liquidity early in the offsets market which is especially important considering there will likely be not enough offsets to satisfy demand. This also will enable firms to hedge more confidently early in the program, further reducing the costs of the program. (IETA3)

> **Response:** We disagree with the commenter concerns, even after the modifications in the First 15-Day Change Notice, that the process for accrediting early action credits and transitioning them to ARB-certified offsets is still too administratively burdensome. However, we recognize all regulations can be improved. Significant changes were made to section 95990 in the Second15-Day Change Notice that further clarify the transition of early action offsets, add greater transparency to the program, and clarify the use of early action offset credits in the program.

M-156. Comment: Section 95990(k) - Transition of Early Action Offset Projects to the Compliance Program: The current language requires that CAR V 2.1 forest projects calculate how many offset credits would have been issued under the ARB compliance protocol from the project start date to the time of transition, and a comparison of that number to CRTs actually issued. If the number of credits would have been greater under the ARB compliance protocol, ARB will issue offset credits to make up the difference. If the application of the ARB protocol would result in fewer credits, then ARB only issues credits according to the Compliance Offset Protocol for U.S. Forests from the date of transition. We think that it is highly unlikely that V 2.1 projects will generate fewer offset credits compared to if they had been constructed using the baseline and project quantification requirements of the ARB compliance protocol. Given this situation, we propose that the requirement to compare offset credits between the two protocols from project start to the time of transition be made optional. This way, project operators can opt to take the approach that generates the fewest offsets, rather than engaging in a complicated paperwork exercise. Calculating hypothetical credits from past will be time consuming, and may not be fully technically possible because 2.1 project developers likely do not have harvested wood product data in the form required by the ARB compliance protocol for past years. Retaining the requirement to calculate the new baseline under the ARB compliance protocol from the original start date and starting new offset credit calculations from the year of the transition makes sense. (PFT3)

> **Response:** We agree and made this an optional provision. If Offset Project Operators or Authorized Project Designees choose not to do the calculation, they would still be issued ARB offset credits on a one-to-one basis if they meet the requirements of section 95990. This provision was made optional in response to stakeholder comments that some projects may not want to go through the calculation process to be issued additional ARB offset credits.

M-157 Comment: Because of relatively minor differences between the CAR and ARB protocols, the number of credits issued by the Climate Action Reserve for an ozone depleting substance (ODS) destruction project may need to be adjusted in the calculation of early action offsets. Given that potential scenario, we recommend that the Regulations specify documentation that must be reviewed by the early action offset verification body:

1) Original Verification Report
2) Certificate of Destruction
3) Reports of Gas Chromatography Analysis
4) Weight Tickets. (EOSC3)

> **Response:** The regulatory verification and issuance of early action credits will be based on the version of the protocol that was initially used in the Early Action Offset Program. We will not recalculate the number of credits generated based on ARB's Compliance Offset Protocol. However, once the offset project transitions to ARB's Compliance Offset Protocol it will be issued ARB offset credits based on the calculations in that protocol.

Regulatory Verification of Early Action Offset Credits

M-158. Comment: Section 95977(e) includes a limit of six consecutive years of offset project data verification. This six year limit needs to be adjusted for the first verification on early action projects and reforestation projects. This is problematic in the first few years due to the availability of verifiers. Also, the first verification may cover 2007 through 2011 vintages (5 consecutive years). Thus, a verifier will need replacement in one additional year of verification (after only two years of actual work). This is costly and there may be limited numbers of verifiers. Another drawback to this limit is that a verifier who is familiar with the project and conducts the first site visit (and the entity most likely to recognize issues) is prevented from doing the second required site visit at the 6 year interval. We recommend that initial or first verifications, regardless of offset credit vintage years generated, should only count as one year towards this verifier year limit. To assure verifier quality, ARB should do random reviews of projects for the purpose of testing the verifiers and thus obviate this verifier replacement requirement. (CFA2)

> **Response:** The commenter's interpretation of the regulation is incorrect. Early action offset credits must be verified according to the requirements in section 95990(f). They do not need to meet the requirements of section 95977(e), now new section 95977.1, as those requirements must be met by offset projects using Compliance Offset Protocols. Once the project transitions to a Compliance Offset Protocol it must meet the requirements of section 95977 through 95977.2.
>
> Section 95990(f) was modified to clarify the requirements for regulatory verification of early action offset projects. The new requirements include a desk review of each Offset Project Data Report (new section 95990(f)(3)) by an ARB-accredited verification body based on all original early action offset project documentation. This provision was added in response to stakeholder comments to streamline the requirements for regulatory verification.

M-159. (multiple comments)
Comment: Section 95990(f)(4) stipulates that if the desk review concludes that the offset project documentation for an Offset Project Data Report year includes an "offset material misstatement" of 3 percent or 25,000 $MTCO_2e$, whichever is higher, then a full re-verification of the project is triggered. Evolution Markets believes that the 3 percent level will create an unnecessarily large amount of reviews, which could impede the generation of an early supply of credits. Therefore, Evolution Markets suggests raising the threshold to 5 percent. This is the level at which projects may not receive Climate Reserve Tonnes from the Climate Action Reserve. Conforming these thresholds will allow ARB to maintain the environmental integrity of the program, while also eliminating unnecessary and expensive re-verifications. (EVMKTS2)

Comment: The regulatory verification requirements in section 95990(f) impose a vague and inconsistent standard for determining whether the early action offset credits were adequately verified. For example, section 95990(f)(3)(A) requires that the review "ensure that the previously provided offset verification services were sufficient to render a reasonable assurance to support the issuance of the early action offset credits." However, there is no guidance as to what is "sufficient" to meet the "reasonable assurance" standard. Is the standard of sufficiency that which was required by the applicable early action protocol? If not, a requirement that holds a project to a standard not applicable at the time of its original verification would seem to undercut the "early action" principle by introducing standards inapplicable and unavailable at the time the project first registered with the early action program. There are only three early action projects verified under the Climate Action Reserve Forest Project Protocol version 2.1. Given that there will not be any more projects registered and verified under this protocol, it will be very difficult to find an ARB-approved verifier who can cost effectively re-verify these projects in accordance with a standard no longer available to other projects. We would be happy to work with ARB to develop an alternative approach to achieving regulatory verification of projects verified under FPP v.2.1. (TCF2)

Comment: It is difficult to assign a materiality threshold retroactively. Should the original verification not meet this threshold, this threshold leaves little recourse for the original verification body. They have no opportunity to amend their original verification activities given this newly determined materiality threshold. Had the stated requirements of the standard/regulation and accompanying materiality threshold been known during the course of the original verification, the verification body would have developed their risk-based verification design accordingly. (SCS2)

Comment: The three percent offset material misstatement for early action projects should be better defined. The stated “offset material misstatement of three percent or more” should be defined relative to what is being compared. This could be three percent of a verifier’s measurement of a sample of forest plots to the original verifier’s sample of the same forest plots, or three percent of the originally verified CRT assertion to the second verifier’s CRT assertion. (SCS2)

Comment: Neither CAR, nor any other widely used voluntary carbon standard and methodology such as VCS, has incorporated a materiality requirement such as that proposed by ARB to assess a three percent offset material misstatement (or any quantitative percentage) of the total CRT assertion. This laborious task of a complete duplication of all of the project developer’s calculations would not be in line with the risk-based approach, and dramatically increase the time and expense of verification. Were ARB to incorporate a fundamentally different materiality requirement, the efficient transfer of Early Action Projects into the ARB’s compliance system will be substantially hampered. (SCS2)

Comment: The three percent metric used to assess the materiality of the Early Action Project is simply not compatible with the current Climate Action Reserve Verification Project Manual or earlier CCAR/CAR verification standards. The current materiality threshold for the Climate Action Reserve to evaluate offset projects such as landfill and livestock, but not forest carbon offset projects, is 5 percent. This value is also consistent with the California Climate Action Registry General Verification Protocol, Version 2.2, which relates to GHG inventory accounting that was in effect when the first forest carbon project was being assessed under the Reserve protocols in 2007. (SCS2)

Comment: The materiality threshold stated in the regulation is 5 percent for overstatements, but not understatements of CRTs. The materiality threshold for the assessment of Early Action Projects is 3 percent and makes no distinction between overstatements or understatements of CRTs. This difference is not justified in the regulation, nor do we believe it is warranted. (SCS2)

Comment: For the assessment of Early Action Projects, ARB could choose to follow the lead of the Public Resources Code, which requires an independent review of appraisals on conservation lands, and assess Early Action Projects under the standards established by the protocol used during the verification. In many cases, the selected protocol for forest carbon early action projects would be the Climate Action Reserve Forest Project Protocol, Version 2.1. It is important to note that the materiality threshold in the Forest Project Protocol, Version 2.1 is different than the previously discussed three percent material misstatement proposed by ARB's draft regulation. The Forest Project Protocol, Version 2.1 does not have a materiality threshold. Rather, it incorporates a Minimum Quality Standard, which considers the 15-percent difference between the verifier's inventory data and the forest owner's from a subsample of plots; and if there is a 10 percent difference between the projected activity line and the actual activity line. Should the requirements of the originally verified protocol be followed, these two requirements would be considered the metrics for evaluating material misstatements. (SCS2)

Comment: PG&E supports ARB's revisions to the Early Action section, which allow a "desk review" of projects for re-verification and further supports ARB's decision to allow the same verifier to do a desk review for all vintage years at the same time. To leverage the verification conducted by these projects and encourage them to participate in the Cap and Trade program, PG&E recommends the desk review focus on whether the initial verification conforms to the ARB's standards. The verifier would confirm that the initial verification sampled the right type and quantity of data, used the correct verification methodology and that the conclusions were reasonable. The verifier would not independently verify the data used or attempt to establish his or her own opinion on the project. This would encourage these existing projects to undergo the verification to become Early Action Offset Credits. (PGE4)

Comment: Under section 95990(f)(4), a finding of "offset material misstatement" for a particular Offset Project Data Report year triggers a full re-verification of the project. Section 95590(f)(4) defines offset material misstatement as a misstatement of the smaller of: (1) three percent or more; or (2) 25,000 metric tons CO_2e. In CERP's view, the three percent threshold may trigger an unnecessarily large number of costly re-verifications, and therefore we suggest changing the percentage threshold in section 95990(f)(4) to four percent. This is a reasonable compromise between three percent and the five percent level at which projects may not receive Climate Reserve Tonnes in the first instance. Accordingly, this compromise level is consistent with the dual goals of upholding environmental integrity and minimizing the number of unnecessary and expensive re-verifications. (CERP4)

Comment: Section 95990(f)(4) provides that in the event of a finding of offset material misstatement with respect to a particular Offset Project Data Report year, the verification body must conduct full verification services for the project "for all years eligible and applicable pursuant to section 95990(c)(1)." It is unclear from this language whether ARB intends full re-verification to apply: (1) only to the year(s) for which there was a material misstatement or (2) for all years for which the project seeks early action credits. ARB officials have told CERP members that they intend the former. Modify section 95990(f)(4) as follows:

> (4) If during the desk review the verification body concludes that the offset project documentation for an Offset Project Data Report year includes an offset material misstatement of three four percent or more or the offset material misstatement equates to greater than 25,000 metric tons CO_2e, whichever is smaller, then the verification body must conduct all offset verification services in section 95977.1 and any additional verification requirements in the protocols identified in section 95990(c)(5) for an early action offset project of that type, for the year to which the Offset Project Date Report applies ~~all years eligible and applicable pursuant to section 95990(c)(1)~~; provided that an offset material misstatement that equates to 10,000 metric tons CO_2e metric or less shall not result in the offset verification service requirements of this section. Offset verification services for each Offset Project Data Report year may be done by the same verification body that performed the desk review and may be applied as one single offset verification service and meet the following requirements. (CERP4)

> **Response:** In the second 15-day changes to the regulation, section 95990(f) was modified to clarify the requirements for regulatory verification of early action offset projects. The new requirements include a desk review of each Offset Project Data Report (new section 95990(f)(3)) by an ARB-accredited verification body based on all original early action offset project documentation. This provision was added in response to stakeholder comments to streamline the requirements for regulatory verification.

M-160. Comment: In many cases, a single project will have many holders of credits. In those cases, the credit holders and offset project operator will have to negotiate an apportionment of the costs of going through the early action process. Two elements of the revised regulations may complicate this process: (1) the apparent requirement in section 95990(f) that any verification report be made public; and (2) the requirement in section 95990(j) that any holder of original early action credits be issued Early Action Credits (provided that it does nothing more than register and prove its ownership of the underlying credit). As a result of these elements, any holder of an early action credit will have the ability to “hold out” in negotiations on the apportionment of verification costs—because the holder will know that as soon as the verification report is completed, it has a right to the resulting Early Action Credit irrespective of whether it contributed to paying the cost of implementing the verification. (CERP4)

> **Response:** In the second 15-day changes to the regulation, section 95990(f) was modified to clarify the requirements for regulatory verification of early action offset projects. New section 95990(f) includes new requirements for regulatory verification that is intended to streamline the process and minimize costs associated with converting the voluntary offsets into compliance offsets that can be used for compliance.

The regulatory verification and transition of early action offset credits to the compliance program is a voluntary step. We established rules in the regulation for those who would like to participate in early action offset program. The Climate Action Reserve and the offset verifiers can work with the project developers and the holders of early action offset credits to transition them to the compliance program; however, we will not act as a facilitator of voluntary contracts and voluntary commitments.

M-161. (multiple comments)
Comment: Section 95990 (f.) of the proposed regulations allows for a "desk review" of early action projects for re-verification as ARB offset credits. Evolution Markets supports this important change, which will assist in streamlining the issuance process and reduce compliance costs. However, Evolution Markets believes that requiring the desk review be conducted by an ARB accredited verifier other than the original verifier of the project is unnecessary to maintain the integrity of the offset conversion process and presents an impediment to efficient generation of offset supply. Evolution Markets recommends that ARB permit any ARB-accredited verifier conduct the desk review, even one that might have previously validated or verified the project in question. (EVMKTS2)

Comment: CERP urges ARB to consider an additional streamlining step. Specifically, if the original CAR verifier for an early action project earns an accreditation from ARB, it should be possible for this verifier to perform the desk review. It is unclear to CERP why this approach would raise any concerns of "bias." Precluding such an approach will result in additional costs without increasing environmental integrity. Modify section 95990(f) as follows:

(1) The project must be verified by an ARB-accredited verification body that meets the accreditation requirements in section 95978. The verification body performing regulatory verification pursuant to this section must be different than the verification body that conducted offset verification services for the early action offset project under the Early Action Offset Program <u>unless the verification body that conducted offset verification services under the Early Action Program is an ARB-accredited verification body that meets the accreditation requirements in section 95978.</u> (CERP4)

Response: We did not make this change. Section 95990(f) was modified to clarify the requirements for regulatory verification of early action offset projects. New section 95990(f)(1) includes new requirements that the verifier performing the regulatory verification services must be different than the one that did the initial verification for the Early Action Offset Program. This ensures that the review is completely independent and unbiased.

M-162. Comment: If an Offset Project Operator and/or Authorized Project Designee does not transition an entire Early Action project to ARB but the current Early Action offset holder wishes to transition their issued offsets, the language relies on the Early

Action Offset Program to submit the Early Action Verification Report(s) to ARB. However, the potential Early Action Offset Program we have spoken to (the Climate Action Reserve) has stated they are unsure whether they have the authority to submit Early Action Verification Reports to ARB. This could be a substantial obstacle to transitioning Early Action offsets and could decrease the availability of offsets in the program. Please help clarify what action the issued Early Action offset holder may take if both the Offset Project Operator/Designee and the Early Action Offset Program decline to submit the Early Action Verification Report(s) to ARB. (CE2CC)

> **Response:** In most cases, the verification reports were provided both to the Climate Action Reserve and the offset project developer. The offset project developer should be able to provide the verification reports to facilitate verification or they can request the Climate Action Reserve to provide those reports on their behalf.

M-163. (multiple comments)
Comment: CERP respectfully requests that ARB add a de minimis tons-based threshold for re-verification below which a finding of offset material misstatement would not trigger a full re-verification. CERP suggests 10,000 metric tons for the material misstatement threshold because it mirrors the level that triggers reporting under the Mandatory Reporting Rule. (CERP4)

Comment: We suggest ARB place a minimum threshold on material misstatement to reduce the burden on small-scale projects and to bring reporting of emissions reductions in line with other articles and regulations. As currently written, a project which generates 4,000 tonnes of reductions could be required to undergo a full re-verification if there was uncertainty of 3 percent (120 tonnes of reductions). There is a strong case for scaling the threshold relative to a project's size, recognizing the costs for small-scale projects of re-verification, the conservative nature of the protocol and the small number of emissions reductions at stake. Indeed, ARB does not require capped facilities emitting less than 10,000 tonnes of CO_2e per year to report under its program at all. We suggest that an appropriate minimum threshold for material misstatement could be 10,000 tonnes. Setting an absolute minimum threshold for small-scale projects would reduce their burden and would be consistent with ARB's approach elsewhere. (CIG2)

Comment: The process for re-verifying projects, as currently drafted, will have a disproportionate impact on the ability of small-scale projects due to the low threshold for a full re-verification and the high costs associated with a re-verification relative to the total number of credits produced by a project. ARB could impose a size threshold here, requiring projects generating less than the threshold for covered sources (25,000 tCO_2e) to be desk-reviewed by the same verifier who verified the project to CAR (and who would need to be accredited by ARB). Where a material misstatement has occurred, the project would need to undergo a full re-verification. (CIG2)

Response: We did not make this change. The requirements for regulatory verification must be met to ensure that the early action offset credits meet the requirements in AB 32 that all offsets must undergo regulatory verification. We cannot rely on a non-regulatory program to perform regulatory verification of offsets that will be used for compliance, and AB 32 requires that all offset credits used for compliance be based on the result of regulatory verification.

M-164. Comment: Recognition of Early Action Offset Credits. Section 95990 (f) – Regulatory verification of early action offsets: We would like to note that the regulatory verification standards are different from the verification requirements of CAR v 2.1 forest projects. We think this could lead to difficulties in getting v 2.1 forest offset early action projects re-verified that are not due to lack of proper verification the first time, but from the application of different measures of success. We recommend that independent verification for regulatory purposes for all early action offset projects be done according to the same standards that applied during the original verification—i.e., following the verification instructions published along with the CAR 2.1 Forest Project Protocol. We also recommend that regulatory verification be done according to a procedural assessment of the methods and practices of the original verifier rather than a quantitative re-calculation. (PFT3)

Response: The commenter's interpretation of how the regulatory verification will be conducted is incorrect. We will issue ARB offset credits on a one-to-one basis for each early action offset credit if the ARB-accredited verifier determines with reasonable assurance that the original Offset Project Data Report should have been issued a positive verification statement. We will not recalculate the number of GHG reductions or GHG removal enhancements achieved by the early action offset project.

We modified section 95990(f) to clarify the requirements for regulatory verification of early action offset projects. New section 95990(f) includes new requirements for regulatory verification that is intended to streamline the process and minimize costs associated with converting the voluntary offsets into compliance offsets that can be used for compliance.

AB 32 requires all offset credits used for compliance purposes to be subject to regulatory verification; we cannot rely on a non-regulatory program to perform regulatory verification of offsets that will be used for compliance.

Early Action Conflict of Interest

M-165. Comment: CERP supports the changes to the conflict-of-interest requirements for early action credits in section 95990(g). The December 2010 version of the regulations required that the new verifier be free of conflicts of interest with the project operator and any and all of the holders of credits from the project. CERP recommended limiting the conflict-of-interest test to the project operator and any holder of a large number of the credits. ARB was responsive on this point, limiting the "conflict-of-interest" test to the holder of 30 percent or more of the credits. CERP believe that the changes now provide a reasonable conflict-of-interest structure for early action. (CERP4)

Response: Thank you for your support on the modifications to the regulation.

Early Action Offset Programs

M-166. Comment: Clarify section 95990(a). Some have read section 95990 to require that the Early Action Offset Program must be one that is continuing to issue offset credits. We would ask that the rule be modified to remove the suggestion that an ongoing issuance of credits is required. Modify section 95990(a) as follows:

(7) Nothing in this rule shall preclude a program which meets the requirements of this section from being an Early Action Offset Program solely because it is no longer issuing offset credits. (GEAG)

Response: We did not include this language in the regulation because the requirements for Early Action Offset Programs are clearly defined in the regulation. It is not the intent of the regulation to require that Early Action Offset Programs continue to issue offset credits, and there is no provision for such requirements.

M-167. Comment: As written, section 95990(c)(5) could be interpreted to mean that only credits issued by the Climate Action Reserve may qualify. That is not the message that has been communicated by ARB with respect to early offsets. Instead, we understand that the referenced CAR methodologies represent the standard for quantification, not the exclusive way to obtaining early action credits. A similar change is appropriate in section 95990(i)(1). Modify section 95990(c)(5) as follows:

(5) Results from the use of one of the following offset quantification methodologies, or methodologies which provide a substantially equivalent quantified result from the same activity: (GEAG)

Response: We did not make the changes requested by the commenter. Section 95990(a) allows any registry that meets the requirements of that section to be approved as an Early Action Offset Program. It is not limited to CAR. Our regulations must be prescriptive, and we must specifically list the protocols that qualify under this section. We cannot use a blanket approval as suggested. In addition, we added section 95990(c)(5)(E) as a placeholder to include additional early action offset protocols in the future. The inclusion of these protocols will have to go through the full regulatory process in accordance with the APA.

M-168. Comment: Section 95990(a)(2)(B) requires an Early Action Offset Program to have a system for tracking ownership and transactions of all offset credits it issues at all times. It is not clear if this means including the secondary market. This may not be reasonable. (SCAQMD4)

Response: There are no statements related to secondary markets in the offsets section or tracking transactions on those systems. We believe this section is clear in its intent.

Sector-Based Crediting

M-169. Comment: Study after study shows that, even with the promulgation of additional protocols, the supply of offsets is well short of demand until the protocols for Reducing Emissions from Deforestation and Degradation (REDD) projects come on line. For this reason, CERP strongly urges ARB to accelerate the process of development of these protocols. Further, we recommend that ARB expand the list of sub-national regions that can participate in the protocol development process and host projects. ARB's current process unreasonably excludes Brazilian states, such as Pará, that have expressed strong and direct interest in working with California, and that are currently working with high-quality, high integrity projects. We urge ARB to bring such states, including Pará, into the fold. (CERP4)

Response: This comment falls outside the scope of the First 15-Day Changes Notice. Because the comment falls outside the scope of the notice, no further response is required. We must undertake a full rulemaking process, including a stakeholder process and an environmental review, to accept REDD credits.

M-170. Comment: Modify section 95991 as follows:

Sector-based offset credits may be generated through reduced or avoided GHG emissions from within, or carbon removed and sequestered from the atmosphere by a specific sector in a particular jurisdiction. The Board may consider for acceptance compliance instruments issued from sector-based offset crediting programs that meet the requirements set forth in section 95994 and originate from developing countries or from subnational jurisdictions within those developing countries~~,~~. ~~except as specified in subarticle 13~~ (CCEEB3)

Response: This comment falls outside the scope of the First 15-Day Changes Notice. Because the comment falls outside the scope of the notice, no further response is required. We must undertake a full rulemaking process, including a stakeholder process and an environmental review, to accept REDD credits.

M-171. (multiple comments)
Comment: ARB is proposing a "nested sectoral approach" to generating REDD credits. The "nested sectoral crediting" approach proposed by ARB poses significant risks to the environmental integrity of California's cap and trade program. Project level crediting significantly increases the risk of emissions leakage, when REDD efforts simply prompt deforesting or degrading activities to shift elsewhere. Section 95994, the ARB rules on sectoral offsets do not reference the rights of indigenous peoples, requiring only mechanisms for public participation. This falls well short of the benchmarks established by the UN Declaration on the Rights of Indigenous Peoples. The World Bank, UN-REDD and the UN Framework Convention on Climate Change have all recognized that

ensuring the rights of indigenous peoples and local communities is essential the success of REDD policies. Project-and subnational-based REDD credits are incapable of meeting the environmental integrity standards demanded by AB 32, and they should be excluded from any cap and trade program in California. (FRIENDSOFEARTH2)

Comment: We are particularly alarmed at plans to allow international forest carbon offsets, known as REDD credits to enter California's carbon trading system. No other carbon trading system in the world has allowed such credits to enter their program because of serious, and perhaps intractable, problems with environmental integrity. However, under the Governor's Climate and Forests Task Force and the REDD Offsets Working Group, California is working with the heads of several provinces and states to provide recommendations to policymakers and to secure REDD offsets. California's tight timetable to create REDD carbon credits is undercutting the years of study, effort, and deliberation conducted by policy-makers engaged in other REDD processes (such as the United Nations Framework Convention on Climate Change, UNFCCC) aimed at ensuring the effectiveness of REDD programs. Successful REDD efforts will require meaningful governance reform, respecting the rights of indigenous peoples and local communities, as well as addressing the underlying drivers of deforestation. These measures take both time and political will and cannot be solved with injections of private capital alone. We therefore urge you to suspend further work on REDD until and unless a decision is taken at the UNFCCC that ensures social and environmental integrity as well as financial market stability. (FRIENDSOFEARTH3)

> **Response:** These comments fall outside the scope of the first 15-day changes to the regulation; therefore, no further response is required. However, there are no provisions that allow ARB to accept REDD credits at this time. We must undertake a full rulemaking process, including a stakeholder process and an environmental review, to accept REDD credits.

M-172. Comment: Approval of additional protocols. We note that even though the regulations concerning sector-based REDD offsets credits are limited in scope, California government officials continue to participate in the Governor's Climate and Forests Taskforce and the REDD Offsets Working Group. We are concerned that this process mirrors past processes to establish the domestic forest offset protocol, which has been criticized for its failure to ensure effective public participation. In the future, ARB must ensure that there are opportunities for review and public comment period, including on the scope and intent of proposed actions. (FRIENDSOFEARTH2)

> **Response:** This comment falls outside the scope of the First 15-Day Changes Notice. Because the comment falls outside the scope of the notice, no further response is required. We must undertake a full rulemaking process, including a stakeholder process and an environmental review, to accept REDD credits.

M-173. Comment: PG&E supports the development and approval of sector-based offset crediting programs. PG&E commends ARB for establishing a working group which is developing recommendations for Reducing Emissions from Deforestation and forest Degradation (REDD) offset criteria which can be adopted by the Board and bring REDD credits into the Cap and Trade program. Because of the lead time required to develop the necessary infrastructure for REDD credits, PG&E encourages ARB to develop a timeline and milestones for the development and approval of REDD criteria and agreements. (PGE4)

> **Response:** This comment falls outside the scope of the First 15-Day Changes Notice. Because the comment falls outside the scope of the notice, no further response is required. We must undertake a full rulemaking process, including a stakeholder process and an environmental review, to accept REDD credits.

Air District Comments Regarding Offsets

M-174. (multiple comments)
Comment: CAPCOA supports the 15-day language included in section 95979(g) that is specific to air districts and will allow districts to verify Offsets in the program. We appreciate this change to the rule language, and we believe it addresses our concern about this provision of the rule. (CAPCOA3)

Comment: We are pleased to see that CARB has incorporated all the points regarding conflict of interest proposed by the District and CAPCOA for section 95979(g). This new provision will ease the way for air districts to offer offset verification services to facilities subject to the regulation. (BAAQMD3)

> **Response:** We appreciate your support.

M-175. (multiple comments)
Comment: SCAQMD may wish to run an offset registry, but this is currently precluded in section 95986. Further, an organization that runs a registry cannot do many other functions related to offsets, such as run projects or verify offsets. Section 95990(a)(3) requires that the program's primary business be operating as an offset registry, and prohibits it from offering any verification services. We have previously requested an exception for air districts from these requirements. (SCAQMD4)

Comment: Section 95986 only allows an organization to serve as a registry if that is the organization’s primary business, and prohibits such an organization from performing many other functions related to offsets. As with our concerns about section 95814, there are legitimate reasons for a regulatory agency to perform multiple functions that, in a non-regulatory organization could create a conflict of interest or compromise the integrity of the program. Air districts will make programmatic choices to enhance efficiencies across air programs, and support effective enforcement and the best overall performance of the program; we are not motivated by profit or other concerns. Restrictions designed to prevent other types of businesses or organizations from taking advantage of or otherwise corrupting the market system are appropriate, but should clearly not apply to co-regulators. CAPCOA strongly urges ARB to include the language previously submitted to address this issue:

“Section 95989. California air pollution control districts or air quality management districts. Notwithstanding any other provision of this regulation, California air pollution control districts or air quality management districts may be approved for multiple roles, including verification for mandatory reporting or Offsets, holding compliance instruments, implementing offset projects that are verified by a third party and approved by ARB, and running a Registry, provided the appropriate training, certification, or approvals are obtained from ARB. Decisions on such approval requests will be provided in a timely fashion.”

In the eight months since the December Hearing, ARB staff has not discussed this language with CAPCOA or met with us to resolve the underlying concern, in spite of our requests to do so. We would like to emphasize that under this language, districts are still required to have the necessary training, certifications, and approvals from ARB, and we do not understand why the language is not part of the 15-day proposal. Again, we strongly urge that it be included. (CAPCOA3)

Comment: Contrary to the inclusion in the Mandatory Reporting Regulation of a presumption that air districts' multiple functions do not constitute a potential for a high conflict of interest, new language in the Cap and Trade Regulation included in section 95986(d)(3) specifically precludes entities (presumably including air districts) from acting both as a verification body and as a provider of registry services. Likewise, section 95814(b)(1) continues to preclude entities (presumably including air districts) from holding compliance instruments if they are also verifiers, verification bodies or manage Offset Project Registries. We continue to believe that the performance of multiple functions is a fundamental characteristic of any regulatory agency. Therefore, we again ask for the inclusion of the language proposed by CAPCOA in a new section 95989: California Air Pollution Control Districts or Air Quality Management Districts, to align the Cap and Trade Regulation with the principle resolved in the Mandatory Reporting Regulation. This would ensure the issue is addressed consistently throughout the Climate Protection Program. Add section 95989 as follows:

> <u>Section 95989. California Air Pollution Control Districts or Air Quality Management Districts.</u>
>
> <u>California air pollution control districts or air quality management districts shall be approved for multiple roles, which include verification of offset projects or emissions data for mandatory reporting, holding compliance instruments, implementing offset projects that are verified by a third party and approved by CARB, and running a Registry; provided the appropriate training, accreditation or approvals are obtained from CARB pursuant to sections 95132, 95978, 95814 and 95986. Decisions on such approval requests shall be provided in a timely fashion.</u> (BAAQMD3)

Comment: Section 95814 precludes any air district that is acting as a verifier from holding compliance instruments. There are legitimate reasons why a regulating agency may need to do this. Districts do hold emission reduction credits (or other credits that are analogous to compliance instruments as the term is used here) in criteria pollutant programs without compromising the integrity of the program. In fact, in every case that a district has elected to do this, it is to ensure the proper, efficient, and effective functioning of the program. CAPCOA has offered to work with ARB to clarify our concerns and derive a mutually agreeable solution. (CAPCOA3)

Comment: Section 95814(b)(1) would prevent air districts serving as a verification body or as an offset verifier from holding compliance instruments. This should be allowed for air districts, as holding a small amount of compliance instruments may be needed for insurance purposes for verification services. (SCAQMD4)

> **Response:** Air districts are able to participate in the cap-and-trade program, but must meet the eligibility and conflict-of-interest requirements in the regulation for whichever role(s) they decide to take. The cap-and-trade regulation provides for distinct roles within the compliance offset program. The roles include project developers, offset verifiers, and approved offset project registries. There is a careful separation of roles for offset project developers, verifiers, and registries, to keep in place a system of independent checks and balances throughout the whole offset system. This parsing of roles is consistent with international standards and best practices, as well as program elements developed within the Western Climate Initiative, and applies to all participants (private and non-private) that choose to be part of the compliance offset program.

M-176. Comment: CAPCOA requests the careful consideration and processing for adoption by CARB of GHG offset protocols that have been fully vetted and developed by California Air Districts. (CAPCOA2)

> **Response:** We are committed to working with air districts to identify new offset protocols that could be included in the cap-and-trade program. As with all protocols and offset project ideas submitted to ARB, we will review and evaluate their potential for use in the program.

M-177. Comment: Section 95979(g)(3) provides special provisions for air districts serving as offset verifiers. It states that if an air district hires a subcontractor who is not an air district employee, then the air district shall be subject to all the requirements of section 95979. This should be changed to "the subcontractor" shall be subject to all those requirements. (SCAQMD4)

> **Response:** We did not make this change. The language is consistent with the same types of provisions in MRR and the treatment of air districts as regulatory agencies only applies as long as the verification team is comprised of air district staff.

Forest Owner Definition

M-178. (multiple comments)
Comment: The forest owner definition in the Compliance Offset Protocol for Forests should be adjusted to be internally consistent and consistent with the cap and trade regulations. The Compliance Offset Protocol for Forests contains two different forest owner definitions on pages 10 and 82. The former definition is consistent with the definition in the Cap and Trade Regulations, Subarticle 2, section 95802(a)(103). However, the latter definition is inconsistent and excludes conservation easement holders from the forest owner definition. This definition needs to be amended, and TNC recommends that the definition in the Protocol be adjusted to reflect our recommendations stated in section 1. (NC8)

Comment: Section 95802(103), we recommend first that the definition "forest owner" be narrowed to those parties with an interest in the land and/or the trees, and further that the forest owner who is designated as the project operator be defined as the responsible party for the offset project. We recommend these changes to the definition of forest owner also be made in the Compliance Offset Protocol for U.S. Forests. (PFT3)

> **Response:** We clarified the definition in the forest protocol and in the regulation with respect to conservation easement holders. The definition states that a
>
> > "Forest Owner is the owner of any interest in the real (as opposed to personal) property involved in a Forest Project, excluding government agency third party beneficiaries of conservation easement; and that Generally, a Forest Owner is the (owner in fee) of the real property involved in a Forest Project. In some cases, one entity may own the land while another entity may have an interest in the trees or the timber on the property, in which case all entities or individuals with interest in the real property are collectively considered Forest Owners, however, a single Forest Owner must be identified as the Offset Project Operator."
>
> We believe this makes the exclusion of easement holders explicit. We also modified text where needed to ensure consistency in the term as defined in the protocol and the Regulation.

Other Offset-Related Comments

M-179. Comment: PCAPCD agrees that offset credits used by a facility for its compliance obligation under the ARB Cap and Trade Regulation should not be used to satisfy the GHG mitigation requirement from any other mandatory program. (PCAPCD2)

> **Response:** No response is necessary.

M-180. (multiple comments)

Comment: The Reserve strongly supports the revised Regulation's inclusion of language requiring that Compliance Offset Protocols use standardized methods (section 95972(a)(9)). The use of such methods helps to reduce uncertainty, inconsistency, and subjectivity in the assessment and quantification of offset projects. However, we recommend that this language be clarified to specifically state that Compliance Offset Protocols must determine the eligibility and additionality of projects using standard criteria rather than project-specific assessments, and that they quantify emission reductions using standard baseline assumptions, emission factors, and monitoring methods. This will ensure that the Board's Compliance Offset Protocols do not suffer from the issues that have occurred in the United Nations Clean Development Mechanism program and other offset efforts that rely on more subjective, less consistent project-specific approaches. (CAR4)

Comment: ACR strongly supports the objective of consistent implementation of all offset projects within a project type. However it is unclear what ARB means by "standardized methods," which is open to subjective interpretation since this is not a term included in the list of definitions in section 95802. We are concerned that this could unintentionally exclude some potential Compliance Offset Protocols that are judged not to meet an undefined requirement. If the intent of the "standardized methods" language is simply to signal that ARB will only approve one protocol per project type—to prevent project developers from bringing new protocols to ARB for review in a project type for which ARB has already approved a protocol—this could simply be stated. ACR recommends section 95972(a)(9) be clarified. Any Compliance Offset Protocols ARB approves by definition will consist of ARB-approved methods, and ARB will have ample opportunity in reviewing and approving Compliance Offset Protocols to determine whether methods are standardized. section 95972(a)(9) could be revised to read: <u>"Consist of ARB-approved ~~standardized~~ methods. It is ARB's intent to approve only one Compliance Offset Protocol per project type."</u> (MARTINN3)

Comment: The proposed revision for section 95972(a)(9) "Consist of approved standardized methods" should be more specific and state that the protocols must use standard criteria for additionality, project eligibility, and standard baselines assumptions, emission factors, and monitoring methods. This would avoid protocols and offsets that rely on project-specific and inconsistent determinations. (EOSC3)

Comment: Section 95972 of the modified draft regulation text adds a new condition that in order to be approved by the Board, compliance offset protocol must: "Consist of approved standardized methods" (section 95972(a) (9)). However, no definition is provided regarding what constitutes "approved standardized methods." To provide greater guidance to methodology and project developers, investors and other offset market stakeholders, ARB should clarify exactly what this provision means, especially as it has several dimensions. First, it would be useful if ARB indicated whether standardized methods relate to the determination of additionality, the calculation of emissions reductions, or both. It may be worth concentrating initially on standardized approaches to additionality, since there is more experience to date with such approaches. Second, it would be helpful if ARB indicated whether standardized methods refer to positive lists, performance benchmarks or other approaches. Finally, it would be helpful if ARB identified the offset project types for which it is seeking standardized methodologies and provided detailed parameters for how those methodologies are to be designed. VCSA has convened an expert committee to draft requirements that will guide methodology developers and others working on performance benchmarks, positive lists and other standardized approaches for determining baselines and additionality. The VCS Steering Committee on Standardized Approaches for Baselines and Additionality is comprised of individuals representing a broad range of stakeholders knowledgeable in the effective functioning of GHG programs including methodology and project developers, environmental non-profit organizations, GHG program regulators, validation and verification bodies, and businesses. The Steering Committee will complete its initial work by late 2011 or early 2012 and VCSA would be happy to share the Committee's recommendations with ARB at that time. (VCSA)

> **Response:** We clarified language referring to standardized methods in the regulation—see new section 95972(a)(9) to alleviate confusion in this area. In addition, we cannot allow a transition from project-based protocols to standards-based protocols because each protocol must be approved by the Board. Approving additional protocols does not fall under the purview of this rulemaking. If we were to adopt any additional protocols that could be recognized for bringing in early action offset credits, it would have to be done as part of a separate rulemaking and approval process.

M-181. (multiple comments)
Comment: CantorCO_2e recommends that CARB amend the Regulation to allow issuance of CARB/air district permits to offset-creating sources. Such permits would be issued to sources under CARB control, would mandate the maintenance of the reductions, and sanctions for non-compliance that would have the dual effect of, in the event that the credits are not maintained, protecting the environment and penalizing (and gain recompense from) the offset creator. (CANTORCO2E2)

Comment: CantorCO_2e recommends that CARB amend the Regulation to allow a source to secure CARB/air district review and approval of credits. Specifically, with offsets useable for new source review, the company creating the reduction must apply to the regulator (i.e., CARB or the anointed Air District) for recognition of such reductions. Upon receipt of an application, CARB should approve those credits that satisfy AB 32 criteria and protocols; or deny those that do not, and conditionally approve those credits which may be subject to revocation. Two different kinds of credits will emerge from this process: those with CARB approval (which cannot be invalidated or withdrawn and which will sell at a premium) and those that lack CARB approval (which the buyer will be aware are at risk of revocation and which the market will discount). (CANTORCO2E2)

Response: We did not make any change. The cap-and-trade program is designed with a clear system for issuance of compliance instruments, under the jurisdiction of ARB to ensure enforceability and oversight of the system. The suggested changes would add complexity to the program without further increasing the system's environmental integrity.

M-182. Comment: For future changes and clarity over a 100 year period, ARB should adopt a numbering system for the protocol versions as surely they will be updated. Since they would apply for at least one crediting period, there will be need to identify which specific protocol applies to a particular project. (CFA2)

Response: Thank you for the comment. We will consider it as we approve and revise Compliance Offset Protocols in the future.

M-183. Comment: Section 95980.1 does not provide for a "registration" step prior to offsets being issued. There are a number of reasons to make a clear distinction between registration and issuance. For example, project developers may want a project to be registered, but, may want to delay issuing, or to seek partial issuance at any point in time, due to commercial and/or cost reasons or because the buyer of the offsets may want the offsets delivered straight into their account (so they maintain full visibility). From a sales point of view, selling and marketing offsets from a "registered" project is better than from a "listed" project. Allowing the project developer to dictate the issuance timeline provides greater flexibility. We suggest that ARB adopts a process similar to the Climate Action Reserve, where the project first becomes "registered" after the acceptance of all documentation related to the verification, and that the project developer then has 60 days to provide for issuance of the credits. In our opinion, 30 days is too short a timeframe to notify, process payment and issue (most companies pay invoices net 30 days), especially where the sums involved are large and may require corporate approvals. (CIG2)

Response: We do not see a need to have a "registration" step in the offsets program. "Registration" is used in other offset programs to show that an initial approval step has been satisfied for the offset project. We will not make a determination regarding the offset project until it has been listed on a public and transparent website and has been assessed by an independent ARB-accredited verifier. This occurs at the time of verification. According to the regulation, an Offset Project Operator must list the project with ARB and submit their first Offset Project Data Report within 24 months of listing. Within five months of submitting the Offset Project Data Report, the operator must verify the GHG reductions and GHG removal enhancements. After the verification process is completed we may issue ARB offset credits for the projects. At this time the project will become listed as active.

M-184. Comment: Camco suggests that ARB provide some benchmarks or indicative caps on transaction, administration and MRV costs. For example, there are no provisions regulating the cost of registering projects and issuing credits, or whether these will be uniform or different for different projects. Providing project developers, verifiers and others engaged in the process will bring more clarity and certainty into the market, and will encourage more project developers to participate. (CIG2)

> **Response:** ARB has established rules in the regulation for those who would like to participate in the program, and we expect the market to price the needed services as appropriate. ARB will not be charging fees; therefore, it is up to the Offset Project Registries and offset verifiers to figure out the terms of third-party contracts with offset project developers and purchases of offsets. ARB will not be involved in third-party pricing.

M-185. Comment: The word “based” in the second sentence of section 95990(k)(1)(D) should be replaced with the word “baseline.” (TCF2)

> **Response:** We agree and made this change.

M-186. Comment: The perjury provisions in section 95990(a)(6) should say "under penalty of perjury under the laws of the State of California.” (SCAQMD4)

> **Response:** We agree and made this change.

M-187. Comment: PG&E found a misspelling of “section” in section 95990(i)(1)(E). (PGE4)

> **Response:** We agree and made this change.

M-188. Comment: We strongly recommend that the accreditation and reaccreditation procedures for verifiers be made more rigorous than currently outlined in the draft regulation. Below we lay out minimum requirements that could be included in the regulation text, or could otherwise be adopted by CARB. Modify section 95132(c)(4) as follows:

(4) The applicant must pass a performance review.

(A) At a minimum, a performance review of a verification body shall include:

1. review of the detailed sampling plans and verification reports from a representative sampling of geographic locations, lead verifiers and project types;

2. visits to a sampling of project sites;

3. visit to verifier primary office to review verification systems;

4. comparisons to other accredited verifiers who have verified projects of the same project type; (variability of verification procedures and interpretations can indicate differences in the quality of the verifications)

5. investigative review of the conflict of interest assessment provided by the verification body; and

6. opportunity for public comment on verification body performance.

(B) At a minimum, a performance review of a verifier involves review of the detailed verification reports and sampling plans from a representative sampling projects and documentation of any discrepancies found during the review. (UCS7)

Response: We included a performance review as part of reaccreditation, but the specific suggested text was not all included in the MRR. Many of these actions are part of program implementation, and therefore are not included in the MRR.

M-189. Comment: Per section 95850, an emission violation is based on the reports submitted by the verification body and reporting entity. We recommend that the Regulation, to the extent possible, prohibit the execution of indemnification agreements between the program participants and the verification/reporting agencies. In order to establish a foothold in the program, it is foreseeable that reporting agencies might offer or facilities might demand indemnification agreements which will provide that, in the event that a violation is established through one of their reports, the reporting agency will bear the penalty. This will dilute the incentive for program participants to accurately report their emissions and may result in the concealment of information from the verification body. (SCAQMD4)

Response: We did not make this change. Reporting entities and third-party verification bodies are able to resolve their own contracting terms. These agreements between private parties in no way circumvent our penalty provisions in section 96014. We retain enforcement authority over all parties involved in the cap-and-trade program.

N. PROTOCOLS

Forest Protocol

Table 3.1

N-1. Comment: The Compensation Rate for Improved Forest Management Offset Projects presented in Table 3.1 conflicts with text in the Regulation which requires offsets subject to intentional reversals to be replaced at a one to one ratio. The Regulation sets a precedent that all compliance instruments are equivalent and can be substituted interchangeably. We recommend that ARB delete this table since it is not applicable given the terms of replacement in the Regulation. (FINITE)

> **Response:** We changed the regulation to clarify how the reversal ratios apply to forest projects. No change was made to the protocol.

Accounting/Baseline/Benefits

N-2. Comment: The summary of the Risk Analysis in Table D-10 still refers to the Project Implementation Agreement, which will no longer be required. (CFA2)

> **Response:** We agree, and in the first 15-day changes to the regulation, modified the language removing the reference to the Project Implementation Agreement.

N-3. Comment: CARB has adopted offset policies imposing restrictions that will inappropriately limit the availability of offsets for the forest products industry. We believe it is important that any offset protocol adopted by CARB appropriately recognize the contributions of sustainably managed forests and wood and paper products to sequester and store carbon and reduce GHGs. We again request that CARB revise the protocols to appropriately recognize these contributions. (AFPA2, AFPA3)

> **Response:** We believe that the Forest Protocol meets the objective of providing offsets that are real, permanent, quantifiable, verifiable, enforceable, and efficient for industries that provide sustainable managed forests and forest products.

N-4. (multiple comments)
Comment: We recommend that ARB explicitly state in section 3.1 that state tax abatement programs are not considered legal constraints as they can be voluntarily entered and exited at any time. (BLUESOURCE2)

Comment: In regards to section 3.1, land use assessment (aka land use taxation and land use tax abatement) programs are common throughout the U.S. and counties. These programs allow forest owners to commit to keeping forested properties as forestland and many require landowners to follow specific silvicultural guidelines. These programs are wholly voluntary to enter into and to exit. However, though while voluntary, once entered into they are legally enforceable until they are exited. (FINITE)

> **Response:** We believe that the requirements in section 3.1 are sufficient to ensure that credits generated provide additional GHG emission reductions or removal enhancements that exceed any GHG reductions or removals otherwise required by law or regulation, or that would otherwise occur.

N-5. Comment: The setting of a default for other Episodic Catastrophic Events is an error (found in CAR 3.2). This category was added for places predominately outside of California, where hurricanes, tornado or extreme high wind events occur, so setting this to default at 3 percent is unfair to California projects and should allow for verifier to review and accept much lower values for lands not found in these types of high wind event areas. Similarly especially unique areas, say in the blast zone of volcanoes should allow the verifier to add a risk factor in this catch-all unique category. (CFA2)

> **Response:** The risk rating for episodic catastrophic events may cover a variety of risks not accounted for in other categories. At the outset of the cap-and-trade program, there are not sufficient data to determine if all the initial risk values that were used to calculate the forest buffer account contribution are appropriate. However, in the absence of better risk data, we believe that it is important to err on the side of having the risk factors too high, to ensure that there is a sufficient quantity of offset credits in the forest buffer account to cover any reversals in the early years. These risk ratings may be decreased or adjusted at a later time once more data are available on the rate of reversals due to various risks and the functioning of the forest buffer account. It is conceivable that these average risk ratings could be made adjusted based on geography, eco-region, and other factors in the future, but it is not possible to conduct such an analysis at this time.

N-6. Comment: Section 3.8.3 of the Forest Project Protocol requires live carbon stock must be maintained and/or increased during the project life. This provision needs to be revised to state that this is required for the crediting period and that after such period standing life carbon stock may increase and decrease as long as it does not fall below that level to support all registered tonnes. This could easily be clarified by adding a 5th exception to the requirement in section 3.8.3 as follows:

5. The decrease in standing live carbon stocks occurs after the crediting period and the residual stocking is above the level that assures all verified credits will be permanent. (CFA2)

> **Response:** We agree and, in the second 15-day changes to the regulation, modified the language using your suggested language.

N-7. Comment: Section 6 of the protocol, which describes the general calculation of baselines for all types of forest projects, provides that modeling of the baseline must assume a 100-year period. The 100-year figure is repeated in the baseline calculation sections for each project type in sections 6.1.1, 6.1.2, and 6.2.1. The 100-year time period is taken from the original Climate Action Reserve forestry protocol, and is sensible in that context because the CAR crediting period is 100 years. However, such baseline estimation is arbitrary in the context of a 25-year crediting period followed by a 100-year permanence period. Because projects can be renewed at the end of a 25-year crediting period, the project life is actually not known at the outset of the project. It would thus make sense to revise the protocol such that the initial baseline calculation is projected for the applicable crediting period. Then, if the project is renewed, the baseline would be recalculated as part of the renewal process. Accordingly, we recommend the following modification to Section 6 (and corresponding edits to the other sections):

To establish baseline onsite carbon stocks, the carbon stock changes in each of the Forest Project's required onsite carbon pools (identified in Section 5.1 to 5.3) must be modeled over ~~100~~ the Forest Project's crediting period. Modeling must be based on the inventoried carbon stocks at the time of the Forest Project's ~~offset project~~ crediting period commencement. (CERP4)

> **Response:** Our requirements regarding crediting periods and permanence are in place for sound technical reasons. It is anticipated that over time, the Forest Offset Protocol will be updated and improved based on science and practical experience. It is complicated both for regulators and market participants to have many different versions of the same protocol in use, so there is a desire for all projects to move to the latest protocols over time. Risk factors related to leakage and forest buffer account contributions are expected to be updated over time, and potentially other requirements related to the forest carbon inventory or verification. We believe that the current baseline requirements are robust, and agree that providing certainty that project baselines will not be recalculated, as a condition of a renewed crediting period is appropriate to provide greater certainty for those developing offset projects. We added a sentence to the protocol to indicate that the baseline for any Forest Project under this version of the Forest Offset Protocol is valid for the duration of the project life following a successful initial verification where the project receives a positive verification statement.
>
> In determining the appropriate length of a crediting period, we sought to balance the need for investor certainty in projects and the recognition that forest projects often involve reductions that accrue over a long period of time, with the need to be able to review project eligibility and additionality, and make improvements to offset protocols at some later date. Economic considerations cannot be the only factor considered. There is no explicit limit on the number of renewals possible for forest projects, so there is the possibility that forest projects can continue to generate offset credits for 100 years or longer if the program remains in place.
>
> Requirements for maintaining permanence are a separate issue from crediting periods. Any GHG reduction or removal that is issued an offset credit by us will need to be maintained for the period of time that we determine, to ensure

permanence—in this case 100 years. While the existing cap-and-trade program is initially set to continue through 2020, we designed a program that can and is expected to continue to operate well beyond that year. However, we cannot consider specific mechanisms beyond the scope of AB 32 requirements at this time.

N-8. Comment: Section 3.4 provides that, in the event of project termination, the Offset Project Operator or Authorized Project Designee must retire ARB Offset Credits issued for the project from the preceding 100 years. This language should be revised to clarify that the time period is focused only on the applicable crediting periods. Accordingly, we recommend deleting “preceding 100 years” and substituting “preceding crediting period(s).” (CERP4)

Response: We did not make this change. The 100-year requirement is in the context of the permanence requirement for sequestered carbon where an offset is generated to allow a GHG emission from a capped entity. Limiting the time period to the crediting period would undermine the way sequestered carbon is treated under the permanence requirements of the regulation.

N-9. Comment: Section 7 provides that all intentional reversals must be compensated. CERP respectfully requests that this requirement be modified so that the requirement applies only to the stocks for which ARB offset credits have been issued. Intentional reversals after the crediting period need not be compensated as long as the stocks that are associated with issued credit during the crediting period(s) are maintained for 100 years past the crediting period end. This interpretation is supported by other language in the protocol; for example, section 3.8.3, example 5, provides that reversals are permissible during the 100-year monitoring period as long as the stocks associated with issued tons are maintained. However, because this is not made explicit, CERP requests that it be more fully clarified in the protocol. Accordingly, we recommend the following modification to Section 7, subpart 2 (and corresponding edits to other sections):

2. The regulatory obligation <u>that</u> all intentional reversals of GHG reductions and GHG removal enhancements, <u>except those that occur after the crediting period and that do not reduce stocks below those associated with the issued tons,</u> must be compensated for through retirement of other Compliance Instruments. (CERP4)

Response: Thank you for your suggestion, but modified language in this section is not necessary. We clarified language in the regulation related to reversals of forestry offset credits to limit replacement to the amount of credits reversed.

N-10. Comment: Section 7.2.2 provides that the buffer risk rating must be recalculated every year that a project undergoes verification. This language must be clarified to make clear that buffer contributions must be made for each year that a project is receiving credits, but not during the 100 year monitoring period (during which verification will also be required). (CERP4)

Response: The regulation is clear that a forest project only contributes to a buffer account as credits are issued. Therefore, we did not make any changes to the protocol.

N-11. Comment: We believe further discussion of section 6.1.1, Estimating Baseline Onsite Carbon Stocks, is needed to add additional clarity. There is a requirement for a pre-site prep inventory for pools that maybe affected by the site prep. While very few pools would be affected by site prep, for early action projects, this pre-site prep inventory cannot be measured. We suggest adding a professional estimate by an RPF based upon non reforested areas nearby and including a specific requirement for a verifier to check this estimate for reasonableness. (CFA2)

Response: The ARB Forest Offset Protocol requirement that carbon pools affected by site preparation activities must be conducted prior to any site preparation activities is contained in versions 3.0 through 3.2 of the CAR protocol, though the requirements are more detailed in v3.2 and the ARB protocol. We are not aware of any early action reforestation projects under v2.1 of the CAR protocol. Consequently, we do not see any barriers to transition for early action reforestation projects that followed the requirements in versions 3.0 through 3.2 of the CAR Forest Project Protocol and conducted inventories of carbon stocks prior to site preparation activities.

N-12. Comment: Section 6.2.1.1 of the Forest Protocol requires that Logical Management Units must “where even aged management is utilized, have a uniform distribution (by area) of 10-year age classes that extend to the normal rotation age (variation of any 10-year age class not to exceed 20 percent).” This is an impossible test, as most areas have histories which prevent this uniform distribution by age class. If there is any necessary test on age class distribution, then it is already included in the project requirements for Natural Forest Management under section 3.8.2 and shown in Table 3.2. (CFA2)

Response: We understand the concern that the definition of a logical management unit (LMU) may not be readily applicable to all management situations. However, the forest protocol recognizes this possibility and offers an alternative approach that is similarly conservative in evaluating whether carbon stocks within the project area are significantly different from the forest owner’s broader management practices in the area. In situations where an LMU containing the project area cannot be identified, the protocol requires that an LMU instead be defined by all lands where the forest owner or its affiliate(s) either own in fee or hold timber rights within the same assessment area covered by the project boundary. This alternative definition should be readily applicable in the situation described by the commenter.

N-13. Comment: Section 6.2.6 for quantifying secondary effects of projects that reduce harvesting, fails to account for differences in timing for baseline estimates and actual project real harvesting. This calculation is done annually and does not take into account timing of harvest and would require secondary effects contributions from projects that over time increase harvest above average baseline carbon harvests and thus have no reduced harvesting secondary effects. Since a project that increases onsite carbon additionality and increases offsite storage of carbon in wood products is sequestering the maximum CO_2 such a result (project) shouldn't be discouraged. This methodology also applies the 20 percent multiplier to total onsite carbon harvested when the leakage effect is only applicable to the harvested wood products, since all other pools are required to be stable or increasing this over-estimates the leakage effect. The required onsite stock maintenance or increase takes care of the carbon in the non-product portions of harvested trees at issue. An identical over estimate occurs in the contribution to landfills for those projects that harvest more than baseline. See Appendix C in section C.4. This calculation requires landfill deductions even though the project increases wood product production as compared to the baseline. In both these cases, the verifier could evaluate the project and determine if the project will actually harvest more than the baseline over the crediting period and correctly calculate these contributions. This decision can be re-evaluated at each 6 year site visit and if need be corrected in the inventory true-up process. (CFA2)

> **Response:** We understand the commenter's concern about the quantification of secondary effects (emissions leakage) due to decreased harvest; however, the forest offset protocol that we adopted addresses this concern already with a change that was initially incorporated into version 3.2 of the Climate Action Reserve forest project protocol and subsequently our protocol. In section 6.2.6, when secondary effects due to harvest are evaluated, the differences between actual and baseline harvest for the current and all previous years are summed. If the result is that actual harvest has exceeded baseline harvest over the life of the project, then the discount is not applied in the current reporting year. However, if the baseline harvest has exceeded actual harvest, then the deduction is applied in the current reporting year. The equation addressing carbon in harvested wood products entering landfills functions in the same manner by evaluating the summed difference between actual and baseline carbon entering landfills over the project life before determining if the deduction will be applied in the current reporting year.
>
> The application of the secondary effects deduction for reduced harvest to total onsite carbon harvested (rather than only the carbon entering wood products) is appropriate because the full effects of emissions leakage involved all the carbon in the harvested trees, and not just the wood products. The deduction for the secondary effects is only applied once, and we do not agree that the onsite carbon stock maintenance requirements account for the non-product portion of the emissions leakage.

N-14. Comment: We encourage ARB to incorporate aggregation rules into the compliance Forest Offset Protocol (or establish forest carbon aggregation through a related, separate protocol). Aggregation makes carbon projects feasible for family forest owners by helping them achieve economies of scale while maintaining high standards for carbon measurement and offset quality. Enabling aggregation will be critical to delivering offset supply from U.S. forests and to ensuring that the carbon markets are not accessible only to large industrial forest owners. Incorporating a version of the Aggregation Guidelines adopted by CAR in August 2010 would level the playing field for family forest owners, help protect older-growth forests managed by families, and provide a significant boost to forest carbon offset supply. (NEWFOREST2)

> **Response:** We recognize the significant potential benefits for the environment and offset supply of lowering barriers to participation for small Forest Owners. However, the aggregation rules for forest projects developed by CAR are a separate protocol, and we will need to conduct further review to determine their compatibility with the cap-and-trade program and specific offset provisions. Any consideration of an aggregation methodology would be part of a separate rulemaking with a full public process.

N-15. Comment: The forest protocols use a number of accounting assumptions that overestimate the climate benefits of ‘improved forest management’ projects compared to internationally accepted approaches. Since these overstated benefits would be offset by an equal number of additional emissions, there could be significant backwards progress for every IFM offset credit sold under the CARB approved system. To measure the ‘with project’ and ‘without project’ climate benefits of forest management, the CARB protocols count all the carbon in wood residues that are used to generate energy as a 100 percent emission rather than as a true carbon benefit that can be measured by the avoided emissions from fossil fuel burning. RPS energy is an integral part of State policy because they increase carbon sequestration of fossil fuels that can stay buried rather than burned to generate energy. Much of the wood residues collected at the logging operation, sawmill operation, and post-consumer collection operations are used for RPS eligible energy in California, but are counted as pure ‘waste’ by CAR. Not counting these energy-related benefits would appear to inflate the number of offset credits ascribed to a project and reduces what had been sustainable harvest levels. Purchasing CAR IFM credits could actually emit more GHGs by ‘creating’ credits by not burning wood residues for energy. This could require re-evaluation of actual climate benefits if the CAR methodology was independently assessed by national or international bodies. (UCB2)

> **Response:** It is appropriate for the forest protocol to treat wood residues as “waste.” Any benefits created by the combustion of these residues at capped sectors as replacement of fossil fuels is accounted for appropriately under the cap-and-trade regulation.

N-16. Comment: CAR asserts that only 20 percent of the forest products not produced as part of the CAR project will be replaced by other forest products. While the 20 percent ‘leakage’ number does a good job in inflating the size of claimed benefits, better estimates of leakage at the global scale that CO_2 operates at, are usually well over

80 percent. Using a 20 percent leakage factor is far below the estimates for generic timber produced in the United States. A number of scholarly articles estimated leakage factors of around 90 percent for west coast conifers. Using the unsubstantiated 20 percent leakage rate rather than a possibly more relevant leakage rate of 80-90 percent creates at least a four-fold change in the baseline calculations for net storage in products. Since the carbon offsets can be sold to emitters anywhere in the world, it would seem that the local benefits of more carbon inventories in a local forest are not the same as the global benefits from increased carbon storage and decreased emissions. (UCB2)

> **Response:** The Protocol attempts to conservatively account for the risk of increased emissions outside the project boundary as a result of project activity. To accomplish this, the Protocol assumes 20 percent of the carbon emissions resulting from reduced harvesting will be shifted to harvest on other lands, either from within or outside of California, to meet market demands. Currently, there is little data available on actual leakage rates. The leakage factors in the Protocol can be updated as better data become available.

N-17. Comment: The forest protocols underestimate how much of the harvested material ends up in forest products, and how long all products will stay in use. It appears that the protocol formulas are based on historical estimates as a proxy for the lifespan of products rather that forward looking estimates for what will happen in upcoming decades. Empirical data analyzed by Skog (2008) documents considerably longer lifespan for products over time. In both the case of estimating the GHG benefits of renewable energy and the lifespan of wood products, the most recent federal accounting uses the numbers in Smith (2009 and Skog (2008) rather than the older and less accurate measurements used in these protocols. (UCB2)

> **Response:** We will review and update protocols as new information becomes available, and we will propose amendments if needed.

N-18. (multiple comments)
Comment: In advance of ARB's adoption of the Forest Offset Protocol in December 2010, a broad coalition of public interest organizations dedicated to forest conservation strongly recommended changes to the Forest Protocol in order to improve the integrity of the carbon accounting in the protocol and to protect forest ecosystems and habitats from adverse impacts caused by the Forest Protocol. These recommendations included: 1) Clarify that the Forest Protocol does not permit forest offset projects to generate credits for converting a diverse, natural forest to a simplified even-age stand; 2) Improved forest management projects must include the forest carbon pools associated with lying dead wood and, when there is intense site disturbance above certain thresholds, soil carbon, in order to ensure accurate accounting. The same day that ARB adopted the Forest Protocol as part of the Cap-and-Trade regulation, the Climate Action Reserve—the entity that had initially developed the forest protocol—made public a series of white papers they had commissioned to provide information on many of these same topics. In short, the white

papers state that soil carbon and down woody debris carbon pools comprise substantial portions of the carbon at a forest site; the carbon in these pools can be greatly mobilized (i.e., result in GHG emissions) by disturbance resulting from intensive management actions such as forest clearcutting and soil preparation; and that accurate accounting of the GHG impacts of forest projects requires accounting for the soil and down woody debris carbon pools in projects that include disturbance of these carbon pools. Following the publication of these white papers, the Climate Action Reserve committed to a series of revisions over the next several months to address these issues. In contrast, the proposed modifications to the Cap and Trade Regulation currently proposed by ARB fail to address these inadequacies in the Forest Protocol, and we have been told that ARB may not take up revisions to the Forest Protocol until 2012 or later. In order to provide accurate accounting in the Forest Protocol, protect forest ecosystems and habitats from adverse impacts caused by the Forest Protocol, and improve the integrity of the Cap and Trade program to the extent that it relies on offset credits from the Forest Protocol, ARB should propose modifications to address these inadequacies. (CBD4)

Comment: Triggers for Offset Protocol Updates. The proposed regulation would benefit from clearly articulating conditions that would trigger a review and update of offset protocols. At a minimum, new research or information that would substantially alter the accuracy of an ARB protocol should instigate a protocol review by ARB. We note that the recent white papers on the Forest Protocol commissioned by the Climate Action Reserve illuminate significant accounting shortcomings as well as opportunities to make the protocol more cost effective for project developers. (PFT3)

> **Response:** We are aware of the papers that CAR released and the ongoing work to revise the protocol established for the voluntary program. We will review new information and periodically revise the Compliance Offset Protocols, if needed. As the protocols are regulatory documents, they are subject to APA requirements and Board action. For program efficiency, we will develop a schedule for review and updates that is efficient and provides certainty to project developers that protocols will not change from year to year. Board Resolution 11-32 directs the Executive Officer to conduct such periodic reviews and propose updates to the protocols, as appropriate.

Federal Land Eligibility

N-19. Comment: TWS applauds ARB on its decision to remove federal land eligibility for projects under the forest protocol until the technical and policy contexts of any such projects are better understood. (TWS)

> **Response:** We thank you for your support.

N-20. Comment: A thorough public and scientific review is necessary to develop a cohesive national policy regarding the appropriateness of use of federal lands in any offset program. National Forests, National Wildlife Refuges, National Parks, and BLM lands exist and should be managed for the full spectrum of ecosystem services and the benefits to human and natural systems that those services represent. Any commitment of federal land agencies to manage for increased carbon sequestration, and participation of these agencies in private offset markets must be consistent with their broad public mission and fully protect other public benefits. The experience of California State lands participating in the California compliance offset program may provide valuable information to inform the development of federal public land policies regarding offsets. (TWS)

Response: No response is necessary.

N-21. Comment: TWS believes that the proposed 15-day changes amended the title of the forest compliance protocol to read "Compliance Offset Protocol for U.S. Forest Projects" in order to distinguish such protocols from protocols in development for projects based in other countries such as Mexico. However, TWS respectfully submits to ARB that "U.S. Forests" is a term of art used to refer to federal forest lands. Therefore, the title of the protocol may be misleading given the explicit exclusion of federal lands from participation in the California Cap and Trade program. TWS suggests that the protocol instead be titled, "Compliance Offset Protocol for Forest Projects in the United States." (TWS)

Response: Thank you for your comment. We believe that the U.S. Forests Protocol title summarizes the ARB forest protocol in the United States appropriately.

N-22. Comment: The forest protocol should not be part of the proposed Cap and Trade rule unless, at the minimum, the following critical amendments are adopted:

a. Forest carbon offset projects may not include conversion of native forests to tree plantations.

A Forest Project may not include conversion of native forest stands comprised of multiple ages or mixed native species to even-age or monoculture management, and may not include even-age management of any stand that had been converted to even-age or monoculture management in the harvest cycle preceding the registration of the Forest Project.

b. Forest carbon offset projects must account for changes in down and dead wood and soil carbon pools.

Forest Projects that include timber harvesting are required to account for changes in the following forest carbon pools: lying dead wood, and soil carbon. (SIERRACLUBCA5)

Response: Under the ARB Compliance Offset Protocol for U.S. Forest Projects (Forest Offset Protocol) harvesting, including clear-cut harvesting, does not generate offset credits. The protocol requires projects to maintain or increase the standing live carbon stocks in the project area. While harvesting may occur, the protocol accounts for harvesting as a decrease in standing live carbon stocks that must be compensated for by an increase in sequestration in the rest of the forest project lands. Offset credits will not be issued if, over any consecutive 10-year period, the data reports indicate a decrease in the standing live carbon stocks. If such a decrease does occur it may be considered an intentional reversal requiring the replacement of all credits issued for the reversed carbon.

In addition to the requirement to increase carbon on project lands, projects must be in compliance with all existing rules and regulations to be eligible for generating offsets. The Protocol does not allow any forest management activity that is not already allowed by state, federal, or local laws and regulations. To the extent feasible, the Protocol includes environmental safeguards to help assure the environmental integrity of Forest Offset Projects. These include requirements for projects to demonstrate sustainable long-term harvesting practices, limits on the size and location of even-aged management practices, and requirements for natural forest management, which require all projects to utilize management practices that promote and maintain native forests comprised of multiple ages and mixed native species at multiple landscape scales.

The protocol also recognizes that lying dead wood is recruited from the standing dead wood pool. The Protocol requires (1) visual inspections of lying dead recruitment by verifiers, and (2) minimum standards for standing dead wood recruitment that is increased if a verifier observes that lying dead wood in the project area is not commensurate with recruitment from standing dead trees. We also recognize that lying dead wood provides important environmental and ecological benefits, but that quantification methods for lying dead wood have relatively high uncertainties. For these reasons, we consider the current carbon accounting framework and protocol requirements to be sufficient to prevent or account for significant decreases in the lying dead wood and soil carbon pools.

N-23. Comment: The forest protocol, as currently written, would allow shortfalls, whether unintentional or intentional to be replaced with offsets of any kind. It is inappropriate to substitute offset credits that are being marketed as benefiting our forests to be replaced by other, unspecified credits that would not capture any of the co-benefits being lost with the forest offset. (SIERRACLUBCA5)

Response: The protocol includes flexibility by providing participants with compliance instrument options to make up for forestry protocol offset shortfalls. We will issue credits based on their ability to reduce GHG emissions, and the subsequent replacement instruments only have to demonstrate that same benefit—to reduce GHG emissions.

N-24. (multiple comments)
Comment: Section 2.1.2 eliminates the opportunity for forest carbon projects which had previously been verified under other voluntary carbon offset programs such as the Chicago Climate Exchange (CCX) and the American Carbon Registry (ACR). Hundreds of thousands of acres of land submitted to the CCX in the mid to late 2000s. The associated offsets are currently worthless and many project owners were never able to sell their offsets before the market crashed. Landowners can cancel their commitments to the CCX as well as ACR by retiring 100 percent of their issued offsets. Once a project is free of all liens and encumbrances associated with a carbon offset registry, it is free to operate as it chooses. By excluding canceled CCX and ACR projects ARB is turning away landowners willing to commit to carbon increasing activities that would not otherwise take place. We recommend that ARB modify this provision so that projects which have properly satisfied the terms of replacement and cancellation can register under ARB. (FINITE)

Comment: Section 2.1.2 eliminates the opportunity for forest carbon projects that had previously been verified under earlier voluntary programs to participate in the ARB program. Once a project has cancelled prior credits and is free of all liens and encumbrances associated with the earlier registry, it is free to operate as it chooses. We therefore recommend that ARB modify this provision so that projects that have properly satisfied the terms of replacement and cancellation of prior registries can register under ARB. (BLUESOURCE2)

> **Response:** We agree with these suggestions and made the appropriate changes to the protocol.

N-25. Comment: CCSF applauds the incentive offered to forests through the development of carbon credits which support reforestation and preservation of California's forests. However, we are concerned that the Compliance Offset Protocol U.S. Forest Projects may create incentives to plant trees in grasslands, which harbor significant native biodiversity in the state of California. The requirements for reforestation projects (sections 2.1.1 and 3.1.2.1 of the Compliance Offset Protocol U.S. Forest Projects) should be amended to include measures to prevent net loss of native biodiversity and prevent conversion of California's grasslands to forest. Native biodiversity should be protected and considered at all scales including species diversity and diversity in land cover and ecological function. (SFMAYOR3)

> **Response:** Projects must be in compliance with all existing rules and regulations to be eligible for generating offsets. The Protocol does not allow any forest management activity that is not already allowed by state, federal, or local laws and regulations.

Qualified Conservation Easement

N-26. Comment: Section 3.5 does not provide an adequate description of what a landowner must do in order to have ARB recognize a "Qualified conservation

Easement." We request ARB issue specific language it requires an easement to contain. (FINITE)

> **Response:** We included additional language in the Forest Protocol package during the second 15-day changes to the regulation that addresses the commenter's concern.

N-27. Comment: Regarding section 3.5(b), since a forest carbon offset project under ARB can be terminated due to both intentional and unintentional reversals (both under the control of the landowner and under provisions for automatic termination under conditions out of the control of the landowner), a Qualified Conservation Easement should not be perpetual. If a project is terminated under the Regulation, the easement naming ARB as a third-party beneficiary, or at the very least ARB's standing as a third-party beneficiary, should be able to be terminate at this time. We recommend that ARB amend this section so that the easement will not have to be in force any longer than the project's carbon commitment and that if the easement is perpetual in nature, ARB's status as a third-party beneficiary be automatically terminated in the event of termination of the carbon project. (FINITE)

> **Response:** We made changes to the protocol to address this concern.

N-28. Comment: CERP requests clarification concerning whether Avoided Conversion projects implemented on public, non-federal land are required to obtain a conservation easement. Section 3.5 of the protocol states: "for Avoided Conversion projects on private land (emphasis added), the forest owner must record a Qualified Conservation Easement against the offset project's property in order for the forest project to be eligible." Section 3.6 provides that: "Avoided Conversion Projects must be implemented on private land, unless the land is transferred to public ownership as part of the program." Section 3.6 also specifies a number of steps that such projects on public, non-federal land must engage in, including public vetting processes sufficient to evaluate management and policy decisions. However, section 4 of the protocol states: "All lands in the project area must be covered by a qualified conservation easement." This language is ambiguous as to whether it applies to Avoided Conversion projects not only on private land, but also those on public land. CERP therefore requests that ARB clarify whether the transfer to public ownership is sufficient for Avoided Conversion projects. If so, such projects should not also have to have a conservation easement. (CERP4)

> **Response:** We modified Section 4 to make it clear that either the Avoided Conversion projects have a conservation easement or they be transferred to public ownership.

N-29. Comment: Section 3.5 does not provide an adequate description of what easement language is required for ARB to recognize it as a "Qualified conservation Easement." We request the specific language ARB is seeking. Moreover, at the conclusion of carbon commitments to ARB the Forest Owner should be allowed to terminate ARB's standing in any easement, as well as the underlying easement itself, if allowed under that easement's terms. Finally, many early action projects will be unable to successfully petition easement holders to bear the administrative and legal costs of evaluating potential new liabilities to ARB established by adding Qualification language, then re-drafting, executing and registering the modified easement. We request that ARB waive this requirement for early action projects or otherwise address this barrier to small landowner participation. (BLUESOURCE2)

> **Response:** We did not make a change, as the protocol is explicit in the types of rights provided to ARB in the conservation easement. We made modifications to terminate our interest in the easement if the forest project has met its carbon commitments or been terminated. We believe the requirement for ARB inclusion in the conservation easement is essential to our ability to ensure permanence in the offset project.

N-30. Comment: Compliance Protocol for U.S. Forest Offsets, Section 3.5 Use of Qualified Conservation Easements. We understand the need for ARB to have the ability to intervene in conservation easement issues that relate to carbon offset projects. However, we think that ARB having the same enforcement authority as the easement holder, and broadly defined to encompass all aspects of an easement is overly broad and could create confusion about roles and responsibilities. We think it is more appropriate to 1) narrow ARB's scope of concern to provisions of easements that affect the integrity of offset projects, and 2) to clearly define the time at which it is appropriate for ARB to intervene in the execution and enforcement of the easement. We believe that requiring holders of qualified conservation easements for carbon offset projects be accredited by the Land Trust Accreditation Commission should provide a layer of assurance that easements will be properly executed and ARB should only have the right to intervene when such land trusts have demonstrably failed to enforce provisions of qualified easements that adversely affect carbon projects. We would like to work with ARB to craft acceptable language. (PFT3)

> **Response:** While the commenter provides some specific cases on how and when our interests could be limited in a conservation easement, we did not make the change. These requirements are written broadly, as we cannot anticipate all situations under which we may need to exercise enforcement authority or intervene to ensure that the permanence requirements of the offset project remain intact. No other commission can substitute for the regulatory enforcement duties of ARB in implementing its programs.

N-31. Comment: The default financial risk continues at 5 percent of all offset credits issued, which is far too high. There is no evidence of a 5 percent rate of financial failure for forest owners. The work group assumed that most projects would also include the deed restriction as well, and received the 1 percent default financial risk, which is a much more realistic value. Small non-capitalized projects may have slightly elevated risk, but still less than 2 percent. We recommend that ARB change the 5 percent to 2 percent and allow the verifier to consider forest owner capitalization and allow reduction even without a Qualified Conservation Easement to use 1 percent. (CFA2)

> **Response:** No changes were made to the regulation based on the comments. The current risk values are conservative, but necessary to ensure the environmental integrity of the program as it is first implemented. If data collected during the implementation support a different risk rating, we will propose changes, as necessary.

Measurement and Verification

N-32. Comment: Measurement and Verification Processes Insufficient to Address Forest-related Mitigation Actions. Section 95973 (b) only requires the Offset Project Operator and any Authorized Project Designees to fulfill all local, regional, and national requirements on environmental impact assessment. Section 95973 (b) should be amended to ensure all local, state, national environmental laws and regulations are met in the course of the offset project. (FRIENDSOFEARTH2)

> **Response:** This comment falls outside the scope of the first 15-day changes to the regulation. Therefore, no further response is required. However, section 95975 requires offset project operators to attest that their projects will meet all applicable local, regional, and national environmental regulations.

N-33. Comment: Section 95977, Verification Requirements: There are a number of weaknesses in the verification section, especially to the extent these verification requirements will apply to any future agreement to include international sector-based REDD offset credits. For sequestration projects, the schedule of verification is wholly insufficient to address the likelihood of both leakage and reversals. The current draft allows sequestration projects to be verified once every six years, and after initial verification, reforestation project can delay verification for twelve years. This is particularly alarming in light of Section 95983 on Forestry Offset Reversals (see below); the State cannot rely on virtuous reporting of intentional reversals and must ensure annual verification of stated greenhouse gas emissions reductions. Section 959779(c) must be amended to require annual verification for all sequestration projects. (FRIENDSOFEARTH2)

> **Response:** While the regulation provides a framework for the potential acceptance of REDD credits, we do not currently have provisions in the regulation to approve those credits or allow them to be used in the compliance program. When it is appropriate for us to begin to consider a REDD regulatory program, we will be analyzing each of these issues very carefully. This would require a separate regulation that includes its own public stakeholder review and a separate regulatory and environmental review process. This comment falls outside the scope of the first 15-day changes to the regulation. Therefore, no further response is required.

N-34. Comment: Section 95977.1 (b)(3)(G) on sampling plans for offset project data reports and section 95977.1 (b)(3)(L) on data checks for offset project data reports are insufficient for addressing the complexity of measuring carbon stocks and fluxes from land based emissions. The use of default values in offset project calculations is widespread and estimates of carbon volumes stored in the respective forest areas vary considerably. A recent study assessing the uncertainty in measuring forest carbon found that, “the overall model output uncertainty reaches an average of +/-43.5 percent” and that “none of the scenarios tested … achieve emissions reductions outside the error margins.” Given the significant uncertainty and error margins in GHG calculations in the forest sector, qualitative narratives of uncertainty risk assessments in baselines, sequestration calculations, among others is not sufficient. Using professional judgment in determining the number of data checks (Section 95977.1 (b)(3)(L)3.) is not adequate to ensure environmental integrity. (FRIENDSOFEARTH2)

> **Response:** The forest offset protocol is written to account for uncertainty and only provide conservative estimates for offset crediting. The regulation does not prescribe the number of data checks that the offset verification team must perform. The offset verification team must exercise professional judgment in choosing these. Ultimately, the offset verification team must have reasonable assurance that: (1) the reported emissions reductions or removals do not contain a material misstatement that would overestimate reductions or removals, or a material misstatement that would underestimate reductions or removals, by more than five percent of the reported emissions reductions or removals, and (2) that all applicable regulatory requirements in the proposed regulation and the applicable protocol have been met in the estimation and reporting of those reduction or removal estimates. We will have oversight of the offset verification team’s verification program to ensure consistency and quality across its verifiers.

N-35. Comment: Section 95983, Forestry Offset Reversals: ARB must further clarify and justify the percentage of ARB offset credits that will be held in buffer accounts will be sufficient to address the problem. While we appreciate the intent to safeguard against both intentional and unintentional reversals, this section does not amount to a prudential approach to risk management. (FRIENDSOFEARTH2)

> **Response:** No changes were made to the regulation based on the comments. The current risk values are conservative, but necessary to ensure the environmental integrity of the program as it is first implemented. If data collected during the implementation support a different risk rating, staff will propose changes, as necessary

N-36. Comment: CERP recommends that ARB apply simplified verification and reporting requirements for a project after the end of its 25-year crediting period. After the crediting period, monitoring will play a different function: that of proving that stocks have not decreased from their levels in year 25 of the crediting period, and monitoring attendant natural forest management requirements. However as currently written, in sections 9.2.1 and 9.2.2, the regulations require the Offset Project Data Reports to contain a variety of information that is not relevant once the credits have been created, such as the application of a confidence deduction, if above 10 percent, for the inventory. In addition, a calculation of the forest buffer contribution or the GHG reductions are not applicable after the crediting period, and should not be required. (CERP4)

> **Response:** No changes were made to the regulation based on the comments. ARB will continue to discuss and evaluate these suggestions, and if appropriate, propose modifications to the regulation.

Clearcutting

N-37. Comment: Do not include forest clearcutting as part of the California's Cap and Trade offset program. Forest clearcutting and the conversion of native forests to tree plantations pose great risk to the climate, while simultaneously degrading forest ecosystems, water quality, and wildlife habitat, and impairing the forest's resilience to the impacts of climate change. Forest projects eligible for offset credit should not include even-aged management (clearcutting), and should not become an incentive for the conversion of native forests to tree plantations. Rather than promote the conversion of native forest to a patchwork of clearcuts, California should use this opportunity to incentivize the best kinds of "green" forms of forest management, which can benefit the climate and the forest. (SIERRACLUBCA5)

> **Response:** No changes were made to the regulation based on the comments. The provisions related to forest management already incorporate existing legal requirements and limits to forest harvesting. Please see responses to similar comments in the Protocols category of Chapter III.

N-38. Comment: We have concerns over the carbon calculations. The Climate Action Reserve issued two white papers demonstrating that our concerns are valid, and we believe emphasize the reason that the Board needs to withdraw clearcut projects from at least Phase I of the program implementation until the problems with accounting are fully examined, justified, and a detailed protocol is developed and adopted for calculating gross and net carbon containment and verification processes. (SIERRACLUBCA5)

> **Response:** We will review new information as it becomes available and revise our protocols as needed. This comment falls outside the scope of the first 15-day changes to the regulation. Therefore, no further response is required.

N-39. Comment: Domestic Forest Offset Protocols Lead to Forest Clearcutting. Forty-seven organizations wrote a letter to ARB in December 2010 raising concerns about the domestic forest offset protocol, arguing that "ARB's proposed cap-and-trade rule currently not only explicitly invites forest clearcutting as a carbon offset project, but also incentivizes the conversion of natural forests into tree farms." When ARB Board members raised questions about the inclusion of forest clearcutting when the protocol was first considered in September of 2009, they were assured that these flaws would be addressed and the forest protocol would become the “gold standard” for forest carbon offsets. Unfortunately, the cap and trade rules adopted by ARB still include forest clearcutting. (FRIENDSOFEARTH2)

> **Response:** No changes were made to the regulation based on the comments. The provisions related to forest management already incorporate existing legal requirements and limits to forest harvesting. Please see responses to similar comments in the Protocols category of Chapter III.

Livestock Manure (Digester) Protocol

N-40. Comment: Section 95852.1.1(b), which restricts biogas projects from receiving carbon credits, offsets or allowances “attributed to the fuel production that would otherwise result in holding a compliance obligation for combustion CO_2,” seems overly broad and counter to what ARB had indicated in the past with respect to offsets from biogas projects. First, it is not clear whether biogas projects are prohibited from claiming ARB-issued offsets or offsets from other programs (such as CAR). If it is the former, then ARB has already determined which projects are eligible to earn offsets through its protocols, and any adjustments with respect to offset project boundaries and which credits can be claimed should be made in the protocols themselves. If it is the latter, it is not clear what authority ARB has to restrict offsets that are issued by non-ARB programs. In any case, the combustion of biogas releases biogenic emissions, which should be treated as carbon neutral. If an offset protocol awards credits for avoided methane emissions, that is a separate “reduction” from the value associated with combusting a biogenic fuel, and awarding this credit does not result in “double counting” downstream carbon benefits. If ARB seeks to restrict offsets from the combustion of the biogenic fuel (but not from avoided methane emissions), it would be much clearer if this adjustment were made in the Livestock Offset Protocol or other future methane destruction credit protocols developed by ARB. We urge ARB to clarify (as it has for Renewable Energy Credits) that generation or use of generation or use or transfer of offset credits from methane destruction projects under the Livestock Offset Protocol and any future protocols that provide for credit methane destruction, or any other recognized protocols for methane destruction, will not prevent biomass-derived fuels from being exempt from compliance obligations. Modify section 95852.1.1(b) as follows:

> ~~(b) An entity may not sell, trade, give away, claim or otherwise dispose of any of the carbon credits, carbon benefits, carbon emission reductions, carbon offsets or allowances, howsoever entitled, attributed to the fuel production that would otherwise result in holding a compliance obligation for combustion CO_2.~~ Generation or use or transfer of Renewable Energy Credits <u>or of carbon offset credits that are available for methane destruction</u> ~~is~~ <u>are</u> allowable and will not prevent a biomass-derived fuel that meets the requirements in this section from being exempt from a compliance obligation. (EM)

Response: We clarified text in the regulation to allow digester projects to sell credits for methane destruction, and for digester biogas CO_2 combustion emissions to be exempt from a compliance obligation.

N-41. Comment: From our experience nationally and internationally, we believe the requirement to have a meter on every destruction device is unnecessary and overly conservative. We know that it will cost over $5,000 per extra biogas meter, further costs for annual maintenance and impose additional risks that the meters may fail, leading to downtime, etc. Where there are identical destruction devices and those destruction devices can be demonstrated to be operating, there is no need for additional meters to determine the gas which flowed to each device. (CIG2)

Response: We agree with the comment and modified the text accordingly.

N-42. Comment: Section 6 of the Livestock Offset Protocol reintroduces language that requires every destruction device to have a meter installed. This individual meter requirement will be onerous for small farms that currently have a number of generators with one meter on the main pipe running to the generation sets. Each individual meter costs $5,000, and there will also be on-going costs for maintenance and calibration. For instance, if one meter goes out of calibration it can cost as much as $1,000 to have it fixed, and the facility will lose the credits that were generated in the month or more it takes to fix the meter. Furthermore, as long as destruction devices are identical, a facility can demonstrate that they are operational by monitoring the performance of flares. This is done by looking at temperature readings which denote their operation. This use of temperature readings is an efficient and less costly proxy that maintains environmental integrity, and should be reintroduced in the final regulations. (CERP4)

Response: We agree with the comments and modified the text accordingly.

N-43. Comment: We strongly recommend that ARB allow project developers to use more updated versions of data, such as volatile solids defaults. This is permitted currently under CAR. Reflecting this in the protocol would reduce the need for project developers to seek clarification from registries who would need to check with ARB. (CIG2)

Response: The APA process requires our regulations to be very specific. Any deviation from the protocols would be considered a noncompliance. We will update protocols with new data and emissions factors as part of period reviews and updates.

Ozone Depleting Substances (ODS) Protocol

N-44. Comment: We believe that an additional refrigerant, CFC-13 (R13) should be added to the list of eligible refrigerants in the Protocol for Ozone Depleting Substances Projects. CFC-13 has been used in low temperature commercial and industrial applications, such as ultra-low temperature laboratory freezers. The Climate Action

Reserve working group had assumed that remaining use and inventories of R13 were negligible. Based on our work with refrigerant reclaimers and facility owners and operators, demand for CFC-13 remains in high demand to recharge high value older equipment. Because of their age and high-pressure requirements, these older units commonly leak, and in many cases, the full refrigerant charge is released. Newer units use ethane, propane, HFC-245fa, HFC-236 and propylene. For industrial process refrigeration, 40 CFR 82 allows a leak rate up to 35 percent. The Climate Action Reserve workgroup compiled data and input from industry and government experts, including the EPA Vintaging Model. That survey reported an average annual leak rate for CFC-13 between 7 and 33 percent. (EOSC3)

> **Response**: We agreed and modified the protocol to include CFC-13.

N-45. Comment: We recommend that ARB conduct verifications on each of the discreet reporting periods within an individual project to ensure accurate accounting for different ODS sources and destruction events. (EOSC3)

> **Response:** We did not make this change. We believe that the documentation and reporting requirements for a 12-month period are sufficient to support rigorous project verification. Each reporting period must have its own offset project data report that is verified separately from the next offset project data report.

O. GENERAL, OPPOSITION, AND SUPPORT

General

O-1. (multiple comments)
Comment: Cap and trade with offsets is too complicated and would require the State to create a whole new bureaucracy. Trading of permits could create spikes in pricing and the inclusion of offsets is an essentially dishonest way of reducing emissions. A straight forward fee on carbon would be simpler and if we rebated all the revenue to California households, then poor and middle class people would be dealt with fairly. The approach to reducing emissions exhibiting the greatest simplicity, efficiency (least cost), and likelihood of being adopted by other states is the Fee and Dividend approach. In this approach, a fee for carbon emissions gradually increases over time to a level deemed likely to achieve the desired emission reductions. As such, emission price certainty is assured, allowing for smoother business and investment planning and therefore greater job creation. All (100 percent revenue neutral) of the fees are returned via check to households so that there is a clear reward for the program to go along with the market incentive to reduce. Also, there are minimal administrative costs to the program and no permit market to regulate. The greatest reason to embrace this approach is its appeal to other states and the country as a whole. We need an approach that is simple, effective, and 100 percent revenue neutral, and attractive for others to adopt. It would jump-start renewables, well-paying jobs, and more effectively lower emissions. Regional disparities would be very minimal. (CCL1, CCL2, CCL3, CCL4)

Comment: I strongly support the use of a carbon tax model in lieu of cap and trade for controlling emissions. A carbon tax is much more transparent. It meets the need for income, which can be used to clean up the effects of pollution, and works as a more direct motivation to polluters to reduce their emissions. I do not think pollution should become a 'market' consideration by allowing it to be a Wall Street commodity. I trust my government to design a tax code that is consistent and effective in limiting pollution. (MORSE2)

Comment: Please develop a fee and dividend program instead of Cap and Trade. It will add a fee to carbon/dirty energy sources and pay a fee to clean energy users and creators. (KENNEY)

> **Response**: We considered alternatives to the cap-and-trade program and implementing a carbon fee was one of the alternatives considered; however, we determined that a cap-and-trade program was more favorable. Details on why we chose cap-and-trade over a carbon fee can be found in Chapter IV of the Staff Report.

O-2. Comment: Consistent with prior CCC recommendations (see www.caclimate.org), the Board should establish an Executive Office-level position with the primary responsibility of ensuring that the very clean technology and facility investments anticipated by the AB 32 program and its complementary measures (e.g., the low carbon fuel standard, the renewable electricity standard and motor vehicle technologies, among other measures) are expedited by the ARB and its sister departments, commissions, agencies and air districts. This responsibility should include appropriate reform of CEQA and air quality regulations so that low carbon fuels and technologies rapidly receive required product or facility performance verifications, certifications and permits. The responsible ARB Executive should submit periodic reports to the Board regarding obstacles, proposed solutions and degree of success. (CCC2)

> **Response**: This comment falls outside the scope of the first 15-Day change notice. However, as stated in the responses to the 45-day package comments, we are committed to integrate all AB 32 and Climate Change Programs and established policies to maximize fuel and energy efficiency that will initiate investments in clean technologies for California's clean energy future.

Opposition

Oppose Cap and Trade Regulation

O-3. (multiple comments)
Comment: Cap and Trade has not been proven to provide the results that this plan is aiming for. Cap and Trade passes on the cleanup costs (or healthcare costs) to the government (i.e. taxpayers), which in the end doesn't benefit the public. (FISCHER)

Comment: In the middle of a great depression, this is not the time to destroy the California economy with this ill-advised cap and trade scheme. (MURRAYD)

Comment: I will begin by expressing my disappointment with the decision to move forward with Cap and Trade. This legislation is a monstrosity, which only serves to suck more money from business and establish another revenue source for people involved in trading CO_2 credits. This is just a system which will, over the years, allow for billions of dollars to change hands, make traders a lot of money, increase business costs while not having any measurable effect on our climate. (KENNERLY2)

Comment: I, as well as my fellow members and citizens of color in California, are being directly attacked based on their race and income. This is another attack of their civil liberties and freedoms as Americans, by taking their moneys away from them in the form of a "get rich" scheme you call Cap and Trade. The ethnic people of this State cannot afford to pay higher prices for electricity, natural gas, gasoline, diesel fuels, as well as the giant spike in the price of every consumer good and service in this state due to the implementation of this Cap and Trade program. The proposed Cap and Trade program is nothing but a giant scheme to make money off of every person and business in California who uses electricity, natural gas, gas, or diesel. Especially affected are the ethnic peoples in this state who have a subsequent lower income due to their race and prejudice in the job force. You are quite aware of how much money you are gaining to make and how you are using this as a monopoly to get rich and to control the people. This is stealing. You are telling the people it is in the name of saving the environment, which it is obviously not. Where would all of this money off of carbon credits be going to? Who is going to get rich off of this? I, as well as my fellow ethnic people's and members of the NAACP, are against this attack on our rights, and economic freedoms imposed by this Cap and Trade program. We are whole heartedly against this and must see it stop now. (NAACP)

Comment: Enough already. Look at what is and has happened to California. High unemployment, second highest taxes in the US already, stagnant growth, businesses leaving California for more favorable states like TX, run away government spending that this will add to as the bureaucracy grows and it is ridiculous to think that this added regulation will reduce any emissions other than running more people out of the State. This proposed regulation needs to be tabled forever and the agency dismantled. (FORMLETTER12)

> **Response:** This comment falls outside the scope of the first 15-day change notice. As we explained in the 45-day responses, we conducted a thorough evaluation of both the health and economic effects of the proposed program to ensure to the extent feasible that no disproportionate negative impact will occur. We have designed the cap-and-trade program to minimize the cost of implementation and compliance and to maximize the overall benefits. Because this comment does fall outside the scope of the notice, no further response is required.

O-4. Comment: Meaningful global action to limit atmospheric concentrations of GHGs can only be achieved through broad action taken across all major global economies. But in the absence of global action, an integrated market-based national policy is the most rational approach to cost-effective, meaningful emissions reductions that can overcome the adverse impacts of leakage, volatility, risk and cost. Further, an integrated market-based national program also provides the most environmentally effective approach to achieving GHG targets at the least economic cost because there is no opportunity for domestic emissions leakage. Climate policy limited to California will be less environmentally effective and have greater economic impacts than comparable efforts implemented within a national Cap and Trade system or even a broad regional system if one were to actually come together with enough participants to make it meaningful and not cost prohibitive to its participants. Given the limited likely effectiveness of a California only program, CIPA believes that it is only under a federal program that policies that can mitigate adverse economic and environmental consequences should be pursued and the current effort under way at the Air Resources Board is a costly exercise that we hope will never be fully realized on the limited geographic basis currently contemplated. To do otherwise would be to embark on a mission that will yield little to the environment at great cost and disadvantage to the state’s economy. Yet, despite the peril inherent in a California only scheme, CARB presses forward with Cap and Trade notwithstanding a flawed design, notwithstanding having already actually met the emissions reductions called for under the authorizing legislation, notwithstanding the failure of the Chicago Climate Futures Exchange and in the face of litigation by forces that would overtake the climate change policy process for their own social ends. (CIPA)

> **Response:** This comment falls outside of the first 15-day change notice. As explained in the 45-day responses, we recognize that we cannot do it alone, but California's economy is among the top 10 largest economies in the world, and therefore is uniquely positioned to take action. Our climate change plan relies on a strong network of climate partnerships. California is working with other states, jurisdictions in the Western Climate Initiative and the federal government to encourage the reduction of greenhouse gases. The flexibility of the cap-and-trade program, together with specific design features included in the regulation to help contain costs, ensures that the reductions needed to meet the requirements of the regulation are cost-effective. Because the comment falls outside the scope of the notice, no further response is required.

Oppose 15-Day Changes to the Regulation

O-5. Comment: The changes that have been made to the Regulations and protocols since they were first proposed have not addressed the flaws that will make them ineffective at solving the critical threat of major climate disruptions that they are allegedly designed to address. (WILLIAMSZ2)

> **Response:** The regulation and protocols are designed to meet the requirements of AB 32. This regulation is one strategy of many developed under AB 32 to reduce GHGs. Please see responses to similar comments in the 45-day section that are related to program design.

O-6. Comment: I do not think these modifications go far enough in this economy to reduce the economic impact. I believe they should be rejected. (GOEDJEN2)

> **Response:** AB 32 calls on ARB to adopt regulations and implement measures to "achieve the maximum technologically feasible and cost-effective reductions in greenhouse gas emissions." AB 32 requires that the reductions be real, permanent, quantifiable, verifiable, and enforceable. AB 32 includes specific standards that apply to regulations that use market-based compliance mechanisms, such as the cap-and-trade program. We have designed the cap-and-trade program to maximize the overall benefits. We evaluated both the health and economic effects of the program to ensure to the extent feasible that no disproportionate negative impact will occur. The overall health and environmental effects of the regulation are expected to be positive, and the program has been designed to minimize the economic costs of the program, which will minimize the effects on low-income communities. The Staff Report provides supporting details on the economic analysis conducted by us in designing the cap-and-trade program.

Support

Cap-and-Trade and AB 32

O-7. (multiple comments)
Comment: GreenX supports the efforts of California and the Air Resources Board to adopt and implement not only a Cap and Trade regulation, but also its efforts to be the model for effective and efficient use of Cap and Trade rules to reduce greenhouse gas emissions in California, and in other jurisdictions in North America. (GREENX)

Comment: Morgan Stanley Capital Group, Inc. strongly supports the use of a cap-and trade program as the best way to achieve reductions of greenhouse gas emissions in California. At an overarching level, we believe the Cap and Trade Rule is largely on target as a workable framework for implementing AB 32. (MSCG3)

Comment: Environmental Defense Fund (EDF) supports the California Air Resources Board's (CARB) most recent actions to improve the efficacy of the Regulation. We believe this Regulation will deliver significant benefits to the state of California. EDF wholeheartedly recommends the Regulation be adopted by the Board without delay. (EDF4)

Comment: Covanta Energy supports the goals of AB 32 and the efforts to reduce GHGs in California. (COVANTA)

Comment: I support cap and trade and am excited to see it go into place in one year's time. It's time we begin to control and decrease our carbon footprint and preserve the one environment we have. This will save lives, create good jobs that benefit society and the Earth, and help us tackle climate change. We can afford this because we must to address climate change. If we wait much longer, it will be too late. (BROWNA)

Comment: Yes on this bill, it is an excellent beginning. There is simply no question that human activity is causing drastic changes in climate. To believe otherwise means one is not reading serious science and is rather like not "believing" in evolution, i.e. what we "believe" doesn't change the truth. We must act quickly and effectively to reduce carbon emissions. As usual, California should lead the way. This bill is a positive step in the right direction. (DAVISSTEIN2)

Comment: I would like to voice my support for the California Cap on Greenhouse Gas Emissions and Market-Based Regulations. It is a responsible first step in controlling the increase of CO_2 for our State and sets goalposts for other western states and the federal government. I am a fisherman and controlling CO_2 emissions is an important step in insuring healthy growing conditions for shellfish as we move into the future. California can be proud of its proactive stance on protecting air and water resources. Action to control CO_2 emissions will have positive effects decades into the future. Acidification of our oceans is a serious threat to aquaculture and wild fisheries in our State. Thank you for looking out for future generations of people and wildlife. (STEELEBR)

Comment: I strongly support the California Cap on Greenhouse Gas Emissions and Market-Based Regulations. It is a reasonable, market-based approach to controlling the increase in carbon dioxide and provides an example of leadership and problem solving for other states and the federal government. I am an environmental scientist with a great deal of experience in water quality and natural resource management in California and other west coast states, including Alaska. I have seen firsthand the evidence for increasing effects of climate change on water supply and natural resources, and am increasingly concerned about the potentially drastic effects of ocean acidification on fisheries and other marine resources. Your decision in support of this program would be an important step toward developing pragmatic solutions to the CO_2 problem that provide incentives for creative problem solving and begin to bring this major externality into the market system. (BERNSTEIN)

Comment: EDF continues to support the programmatic design of a market with free allowance distribution at the outset and a transition to a system that auctions a majority of allowances over the next compliance periods. (EDF4)

> **Response:** We acknowledge your support on the cap and trade regulation and our efforts to reach the greenhouse gas (GHG) reduction goals required in the California Global Warming Solutions Act of 2006, Assembly Bill 32.

Components of the First 15-Day Change Notice

O-8. (multiple comments)
Comment: CSCME is pleased that CARB recognizes the importance of offsets as both a cost-control mechanism and a way to advance the goal of GHG emissions reductions. Offsets are an important tool to help minimize leakage. (CSCME4)

Comment: CERP supports the goal of ensuring that California creates an environmentally rigorous and highly functional offset system in order to contain the costs of achieving the AB 32 emission limits and to serve as a model for other regional and federal greenhouse gas regulatory programs. (CERP4)

Comment: We support the decision by the California Air Resources Board (CARB) to adjust the start date for compliance to 2013. This adjustment will allow the regulated industries the time necessary to assure their reporting and emission reduction protocols are in place, as well as, allow CARB the time to make any fine-tuning adjustments to the program to ensure its success in meeting AB 32 implementation goals. (AB32IG2)

Comment: IEP thanks staff for their attentiveness to stakeholder input during this rulemaking, and notes there are important improvements in the July 27th version of the Cap-and-Trade regulation. IEP appreciates the amendments CARB has made to Section 95852.2, which will aid in encouraging Municipal Solid Waste conversion projects. Second, IEP supports the change to the compliance periods, so that the first compliance period only contains the 2013 and 2014 emission years. This will allow more time to test the auctions and auction software, and better evaluate market stability concerns. Finally, IEP is pleased to see CARB's treatment of allowance auction revenue, such that auction proceeds shall be used exclusively for the benefit of retail ratepayers of each electrical distribution utility consistent with the goals of AB32, while also requiring that each electrical distribution utility report on the use of auction proceeds and allowance value. (IEPA2)

Comment: CAW supports the decision not to exempt the emissions from the combustion of municipal solid waste from having to hold compliance obligations under the cap-and-trade program. The July 7th discussion draft contained a categorical exemption for municipal solid waste incinerators, a significant and arbitrary change for which no public process had been held, and, while this was subsequently removed, we urge you not to include this exemption in any future changes to this Regulation. (CAW)

> **Response**: We acknowledge your support on various components of the first 15-day change notice.

P. USE OF AUCTION PROCEEDS

General

P-1. (multiple comments)
Comment: ARB should work with the legislature to establish a program that commits use of allowance revenue to the investment categories identified by the Economic Allocation and Advisory Committee and supported by Board resolution last December. While TNC acknowledges that ARB may not have full authority to determine how allowance revenue may be used, we urge ARB to work with the legislature to develop an infrastructure that facilitates the investment of allowance revenue consistent with the recommendations of the Economic Allocation and Advisory Committee, published in March 2010, and subsequently endorsed by the Board in its December 16, 2010 resolution (Resolution 10-42). These categories supports funding for, among other things, adaptation of natural systems to climate change (e.g., nature-based adaptation), land use and transportation, job training, disadvantaged communities and regional and local governments. Investments in these categories are critical to facilitate additional greenhouse emission reductions and help nature and people adapt to the unavoidable impacts of climate change. (NC8)

Comment: The Board should embrace the following principles for applying auction revenues. Auction revenues: i) from any sector should be applied primarily to greenhouse gas emission reductions from within that sector; ii) from all sectors should be used for comparable purposes; and iii) to the extent consumer rebates are offered, similar rebates should be available to consumers of fuels and other consumer products as well as electricity. (CCC2)

Comment: If an auction is instituted, the auction proceeds should go back into advancing energy efficiency. (NAIMA2)

> **Response:** These comments fall outside the scope of the first 15-day changes to the regulation. The Governor and Legislature have the ultimate authority on directing the use of auction revenue; therefore, no specific language was included in the initially proposed regulatory language or the first 15-day changes to the regulation. Resolution 10-42 includes the Board’s suggestions for use of auction proceeds. Furthermore, in Resolution 11-32 the Board directed the Executive Officer to develop recommendations for the appropriate use of auction revenue. These recommendations should consider the Board’s direction in Resolution 10-42.

P-2. Comment: CARB's proposal to raise funds via an auction for reasons outside of administrative fee purposes is beyond CARB's regulatory authority. CARB justifies an auction system as a means of lowering GHG emissions and satisfying requirements under AB 32. CARB proposes that revenues from an auction be appropriated to fund programs such as a community benefits fund, green collar employment training, and a low carbon investment fund. These and other proposed programs are outside the scope of administrative fees. We ask CARB to keep in mind that fees must be closely tied to the regulatory programs serving the fee payers, otherwise, these fees are actually taxes and are subject to a two-thirds vote of the legislature. Without a legitimate nexus, the above mentioned auction revenue proposals will likely be challenged as they are contrary to the legislative intent of AB 32. (CALCHAMBER3)

Response: This comment falls outside the scope of the first 15-day changes to the regulation. Nevertheless, in Resolution 11-32 the Board directed the Executive Officer to develop recommendations for the appropriate use of auction revenue. These recommendations should consider the Board's direction in Resolution 10-42.

P-3. Comment: The Cap and Trade regulation provides that proceeds from the sale of allowances will be placed in the Air Pollution Control Fund for appropriation by the Legislature for the purposes designated in AB 32. TWS urges that ARB explicitly reference the 2010 report of the Economic and Allocation Advisory Committee (EAAC) in the Cap and Trade regulation as an articulation of possible relevant uses of AB 32 allowance value. As the economic, financial, and policy experts on the EAAC found, investments in adaptation will be especially important, including investments in ecological services that are not dependent on offsets for funding. California's natural systems provide multiple benefits to current and future generations. The resiliency of these natural systems is increasingly threatened by climate change impacts and the loss of these systems will imperil the health and economic welfare of California. (TWS)

Response: This comment falls outside the scope of the first 15-day changes to the regulation; however, we stated in Board Resolution 10-42 that the Board agrees with the uses of allowances recommended by the EAAC, including the use of revenue for economic opportunities and environmental improvements in disadvantaged communities.

Additionally, in Resolution 11-32 the Board directed the Executive Officer to develop recommendations for the appropriate use of auction revenue. These recommendations should consider the Board's direction in Resolution 10-42.

P-4. Comment: We urge the Board to include provisions in the Regulation to initiate a Community Benefits Fund from the outset of the Cap and Trade Program, funded by a minimum four percent of allowances from the industrial and electricity sectors. Funds should be used for programs or projects in the most impacted and disadvantaged communities identified by ARB for:

- Air pollution and climate change mitigation measures;
- Community public health programs;
- Green-collar employment opportunities in these communities. (SIERRACLUBCA5)

Response: This comment falls outside the scope of the first 15-day changes to the regulation. Per Board Resolution 10-42, we will deposit a minimum of 10 percent of annual proceeds generated from the direct auction of allowances in the Air Pollution Control fund for appropriation by the Legislature to programs and projects that reduce GHG emissions or mitigate direct health impacts of climate change and promote green-collar employment opportunities in California's most impacted and disadvantaged communities.

Additionally, in Resolution 11-32 the Board directed the Executive Officer to develop recommendations for the appropriate use of auction revenue. These recommendations should consider the Board's direction in Resolution 10-42.

P-5. Comment: Is returning allowance value to households as a dividend compatible with the regulation? My reading of the current Cap and Trade Regulation still allows for at least a portion of allowance value to be returned to households as a rebate or dividend in two ways. In the electricity sector, utilities receive free allowances, turn around and auction those to generators, and then use some or all of those revenues as a dividend to consumers. When transportation fuels enter the cap in 2015 in the second compliance period, they will presumably be auctioned to fuel providers, and those revenues may be returned to consumers as a dividend. Is this correct? Will the 15-day changes be more specific about this? Are there other ways consumers may be made whole as costs are passed down to them? (CARBONSHARE2)

Response: We do not believe that it is appropriate to include specific language in the regulation about the use of auction revenue, as this will ultimately be decided upon by the Governor and Legislature. However, in Resolution 11-32 the Board directed the Executive Officer to develop recommendations for the appropriate use of auction revenue. These recommendations should consider the Board's direction in Resolution 10-42. Furthermore, in Resolution 11-32 the Board directed the Executive Officer to work with the California Public Utilities Commission (CPUC) and publicly owned utilities to reflect the findings of the Board that the impact of the cap-and-trade regulation on electricity rates creates appropriate incentives to further the goals of AB 32. In this resolution, the Board further directed the Executive Officer to work with CPUC and publicly owned utilities to reflect the finding of the Board that if allowance value provided to the electric distribution utilities for ratepayer benefit is returned directly to customers, it is consistent with State efforts to promote energy efficiency and energy conservation.

P-6. Comment: Can ARB offer a dividend to consumers in 2012? Although only limited allowances will be auctioned into the system, even a small dividend could have a big impact on public perception of the program. The recent withdrawal of New Jersey from the Regional Greenhouse Gas Initiative is a cautionary tale for what could happen if allowance value is used for efficiency programs that are invisible to most consumers. Because consumers did not see a direct connection to the use of revenues, the lack of consumer support failed to prevent New Jersey's new Governor from withdrawing his state from the program a few months ago. An immediate 2012 dividend could help California avoid this fate. (CARBONSHARE2)

> **Response:** We appreciate your comment; however, specific uses for auction revenue will be determined by the Governor and Legislature.

P-7. Comment: ICCT recommends a streamlined allocation process that is appropriate for small businesses that are eligible for free allowances for transportation hydrogen. The Cap and Trade opt-in procedures may not be appropriate for a small renewable producer that has zero emissions or other small producers with small emissions that can be determined based on LCFS data. (ICCT3)

> **Response:** Small businesses that wish to receive allowances for hydrogen production may do so by becoming opt-in covered entities.

P-8. Comment: In the utility sector, every recipient of allowances should be required to invest their full value on AB 32-related purposes, including cost-effective energy efficiency, renewable electricity, and rebates to low-income consumers. ARB should provide guidance on how utilities spend the allowance value to assure that funded programs are additional and cost-effective, and should require specific and uniform reporting by the utilities. (SIERRACLUBCA5)

> **Response:** We agree that allowance value given to utilities must be used for AB 32-related purposes, and we specified such limitations in section 95892 of the regulation. Section 95892(a) and 95892(d) ensure that allowance value given to a distribution utility will be used on behalf of ratepayers, and in ways that are consistent with AB 32 statutory objectives.
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> To this end, in Resolution 11-32 the Board directed the Executive Officer to work with the CPUC and publicly owned utilities to reflect the findings of the Board that the impact of the cap-and-trade regulation on electricity rates creates appropriate incentives to further the goals of AB 32. In this resolution, the Board further directed the Executive Officer to work with CPUC and publicly owned utilities to reflect the finding of the Board that if allowance value provided to the electric distribution utilities for ratepayer benefit is returned directly to customers, it is consistent with State efforts to promote energy efficiency and energy conservation.

P-9. Comment: We recommend additional incentives for transitioning to renewable steam and electricity and energy efficiency measures for both crude oil production and refining. (ICCT3)

> **Response:** We believe that the structure of the cap-and-trade program, including coverage and allocation to crude oil production and refining, creates the correct incentives for increased energy efficiency and use of renewable steam

production and electricity generation technologies.

P-10. Comment: At the December 2010 meeting, ARB agreed to include the EAAC recommendations on use of allowance revenue in the Board's final recommendations to the legislature on how the state may allocate future allowance revenue. We strongly urge the Board to include the EAAC recommendations in its final recommendations to the legislature on allowance revenue allocation. The EAAC recommendations are in keeping with other interagency and advisory groups recommendations on allowance revenue, particularly on how allowance revenue can support California agriculture in addressing climate change. In their final report to the Governor, EAAC recommended investing a portion of allowance revenue in biological carbon sequestration activities in agriculture and forestry. Their recommendations were echoed by other advisory bodies for AB 32. We cannot rely entirely on the carbon markets to achieve GHG emission reductions in agriculture. The marketplace lacks adequate funding for research to understand opportunities within farming systems to achieve GHG emission reduction. Translating research findings into real opportunities for California agriculture to provide voluntary GHG reductions requires technical assistance. In some cases, when transition costs may be high, financial incentives for farmers are essential. Allowance revenue can turn research into opportunities for certain agricultural activities to help meet the state's GHG targets. And for small and mid-scale California farmers and ranchers who may not benefit significantly from the carbon market because of the size or nature of their operation, state-oriented conservation programs may be a more viable alternative to assist them in reducing barriers to on-farm conservation efforts. We strongly urge the Board to support the recommendations of EAAC as well as the AgCAT and ETACC by including in its recommendations to the legislature competitive grants for research, technical assistance and financial incentives for agricultural practices that reduce GHG emissions and sequester atmospheric carbon while providing environmental and health cobenefits. (CACAN3)

> **Response:** We believe that the comment is not requesting specific amendments to the regulation and is more appropriate for the prospective process we will initiate to develop recommendations for use of auction revenue to the Governor and the Legislature. We stated in Board Resolution 10-42 that the Board agrees with the uses of allowances recommended by the EAAC, including the use of revenue for investments in low cost GHG emission reductions including investments in energy efficiency, public transit, transportation and land-use planning, and research, development and deployment. Further, in Resolution 11-32 the Board directed the Executive Officer to develop recommendations for the appropriate use of auction revenue. These recommendations should consider the Board's direction in Resolution 10-42.

Use of Consignment Auction Proceeds

P-11. Comment: Section 95892(a) was added to explicitly state CARB's intent that allowances allocated to electrical distribution utilities are to be used for ratepayer benefit, and any proceeds from the sale of allowances be similarly used for ultimate ratepayer benefit. The Regulation does not provide detail for how this would be managed to ensure there is a ratepayer benefit. (VALERO2)

> **Response:** The allowance value given to distribution utilities will be used on behalf of ratepayers and in ways that are consistent with AB 32 statutory objectives. We also acknowledge that distribution utility proceeds from the sale of allowances at auction will be subject to limitations imposed by either the CPUC or by the governing bodies of publicly owned utilities. To this end, in Resolution 11-32 the Board directed the Executive Officer to work with the California Public Utilities Commission (CPUC) and publicly owned utilities to reflect the findings of the Board that the impact of the cap-and-trade regulation on electricity rates creates appropriate incentives to further the goals of AB 32. In this resolution, the Board further directed the Executive Officer to work with CPUC and publicly owned utilities to reflect the finding of the Board that if allowance value provided to the electric distribution utilities for ratepayer benefit is returned directly to customers, it is consistent with State efforts to promote energy efficiency and energy conservation.

P-12. (multiple comments)
Comment: ARB should delete sections 95892(d)(3)(B) and (d)(3)(C), which purport to establish utility rate design, since they are at odds with ARB's allocation method across utilities described in detail in Appendix A to the 15-day Modifications to the cap-and-trade regulation, and since they attempt to usurp the PUC's exclusive authority governing the setting of utility retail rates. These two sub-sections of the cap-and-trade regulation were adopted at a time when it was still unclear whether ARB would base the allocation to individual electric utilities on a transition to a sales-based approach proposed by the CPUC and CEC or a method based on compliance burden. A sales-based approach would provide a price signal, while a compliance burden approach would not. Since ARB adopted an allocation in section 95892 Table 9-3 based on compliance burden, it should allow the CPUC the same flexibility to adopt a similar approach, if it chooses, in rate-making instead of keeping the outdated language in Sections 95892(d)(3)(B) and 95892(d)(3)(C). Sections 95892(d)(3)(B) and 95892(d)(3)(C) should also be deleted since they are in conflict with AB 32, in that the language expands the scope of that statute's authority, and the language conflicts with the California Constitution and the Public Utilities Code, which, read together, convey exclusive rate-making jurisdiction to the CPUC; OAL may strike down the language on its own initiative. To avoid this outcome, ARB should strike sections 95892(d)(3)(B) and 95892(d)(3)(C) of its own accord. To be consistent with ARB's demonstrated intent to allocate allowance revenue to assist in mitigating compliance burden, to recognize section 95892(d)(3) Sections (B) and (C) go beyond ARB's authority, and to avoid legal challenges, modify section 95892(d)(3) as follows:

> ~~(B) To the extent that an electrical distribution utility uses auction proceeds to provide ratepayer rebates, it shall provide such rebates with regard to the fixed portion of ratepayers' bills or as a separate fixed credit or rebate.~~
> ~~(C) To the extent that an electrical distribution utility uses auction proceeds to~~

~~provide ratepayer rebates, these rebates shall not be based solely on the quantity of electricity delivered to ratepayers from any period after January 1, 2012.~~ (SEMPRA3)

Comment: SCE supports the use of all GHG allowance revenues received pursuant to auctions under the Cap and Trade program for customer rate relief. However, SCE disagrees with section 95892(d) and the "fixed rebate" language in particular because it exceeds the scope of ARB's authority. AB 32 does not grant ARB authority to direct how investor-owned utilities (IOU) should use revenues earned from the sale of emissions allowances. It is the CPUC that has the exclusive authority over this rate-setting function. Pursuant to the California Constitution, the CPUC has general regulatory authority to fix rates and assure that rates and allocation of costs are just and reasonable, and nondiscriminatory. Likewise, the Public Utilities Code grants the Commission specific authority to fix and design rates. Accordingly, the CPUC's jurisdiction over rate-setting and rate design is exclusive. Apart from the fact that ARB lacks authority to promulgate this "fixed rebate" language, the "fixed rebate" approach will not achieve the most equitable, cost-effective policy outcome for Cap and Trade. SCE recommends allowance revenues should be returned to customers in proportion to the costs incurred by such customers for GHG compliance, or "volumetrically," rather than through the use of a fixed rebate. Furthermore, all of the allowance revenues should be returned directly to customers, rather than funneled to other programs. A volumetric approach is preferable because it is a less expensive and more equitable way to reduce emissions, will garner broad public support for future Cap and Trade programs, and is more likely to result in a successful GHG reduction program. (SCE3)

Comment: Section 95892(d) sets forth restrictions on the use of auction proceeds, including a requirement that any ratepayer rebate: (1) be applied to "the fixed portion of ratepayers' bills or as a separate fixed credit or rebate" and (2) "shall not be based solely on the quantity of electricity delivered to ratepayers from any period after January 1, 2012." PG&E continues to have serious concerns with the ARB restrictions on the CPUC-regulated use of auction proceeds specified in section 95892 including subsection (d)(3)(B) and (d)(3)(C). AB 32 specifically preserves and reaffirms the CPUC's jurisdiction over utility rates, stating: "(n)othing in this division affects the authority of the Public Utilities Commission." Therefore, ARB's proposal to directly mandate how allowance proceeds should be included in CPUC-regulated utility rates in a specific manner exceeds the scope of ARB's jurisdiction and should be deleted. (PGE4)

Comment: The instructions on the use of allowance auction proceeds contained in section 95892(d)(3)(B) and (C) go directly to the CPUC's regulatory discretion to set electric rates. CARB has no authority to direct the CPUC to make rates in any particular manner and it should not attempt to do so here. CLECA therefore urges the CARB to remove subsections (B) and (C). (CLECA)

Comment: In deferring to the CPUC and the California Legislature on electric ratemaking matters, the ARB can and should consider the carbon-related conservation and price signals already embedded in existing CPUC-regulated utility rates and programs. The current tiered electricity rate structure mandated for residential customers by the Legislature and CPUC, the carbon price premium directly and indirectly included in wholesale electricity procurement prices and passed through to all retail customers, and the existing utility customer-funded Energy Efficiency programs for all retail customers, provide incentives and support for carbon emission reductions through energy savings. Any further price signal from the cap-and-trade program would only be imposed on a small subset of customers due to existing rate design restrictions and would disparately punish those upper-tier consuming households who already pay rates for marginal consumption far in excess of cost of service (and thus see very strong price signals to conserve). It would also unfairly and ineffectively punish non-residential customers who already have adopted carbon-minimizing energy efficiency measures (e.g., large but efficient industrial customers would be penalized for being large rather than rewarded for being efficient). PG&E therefore recommends deletion of sections 95892(d)(3)(B) and 95892(d)(3)(C) in full. (PGE4)

Comment: The CPUC has exclusive jurisdiction over Investor-Owned Utility ratemaking and is solely responsible for determining how consignment auction proceeds are distributed to utility customers. Current rates and programs already send a strong conservation signal to customers, and an additional carbon cap-and-trade price signal will unfairly penalize a subset of customers who already see incentives to use less energy. (CCEEB3)

Comment: Under the California Constitution, the CPUC has been provided exclusive jurisdiction over the ratemaking for Investor-Owned Utility costs and revenues, and thus is solely responsible for determining how consignment auction proceeds are distributed by Investor-Owned Utilities to utility customers. Therefore, ARB would exceed its authority by issuing regulations that would require the utilities to return the auction proceeds they receive to ratepayers in a specific manner. Current electric rates and programs already send a strong conservation signal to households who consume in upper tiers. An additional carbon Cap and Trade price signal will unfairly penalize a subset of customers who already see incentives to use less energy. (PGE4)

> **Response:** We acknowledge that electrical distribution utility proceeds from the sale of allowances at auction will be subject to limitations imposed by either the CPUC or by the governing bodies of publicly owned utilities, and that these entities have exclusive electricity ratemaking authority. Based on these grounds, we removed the language that the commenter refers to as “fixed rebate” language.
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> However, proper carbon pricing is the primary way in which the cap-and-trade program achieves emissions reductions. Compensation provided volumetrically (per MWh consumed) will not create the correct incentives for greenhouse gas reduction. Volumetric return of allowance value eliminates incentives for GHG reduction strategies such as conservation of electricity, efficient combined heat and power, and distributed electrical generation.

To this end, in Resolution 11-32 the Board directed the Executive Officer to work with the CPUC and publicly owned utilities to reflect the findings of the Board that the impact of the cap-and-trade regulation on electricity rates creates appropriate incentives to further the goals of AB 32. In this resolution, the Board further directed the Executive Officer to work with CPUC and publicly owned utilities to reflect the finding of the Board that if allowance value provided to the electric distribution utilities for ratepayer benefit is returned directly to customers, it is consistent with State efforts to promote energy efficiency and energy conservation.

When we determined that allowance value should be allocated to electrical distribution utilities on behalf of customers, we made this decision with the explicit understanding that value would not be used to skew carbon pricing or reduce incentives for GHG reductions. We retain the authority to revoke free allocation if it is used in a way that is counter to the statutory objectives of AB 32.

We note that our Economic and Allocation Advisory Committee (EAAC) recommended against allocating allowance value to electrical distribution utilities because the EAAC believed that preventing increases in electricity rates would be the likely outcome of this allocation approach.

Carbon price signals in electricity rates should reflect the emissions rate of the marginal generator dispatched into the power markets. In establishing the appropriate carbon price in rates, the CPUC and POU governing boards will need to account for the costs of other GHG-reducing policies, including the 33 percent renewable portfolio standard and the impact of these programs on electric rates.

P-13. Comment: LGSEC opposes the limiting language of the proposed revision in section 95892 as it appears to allocate all allowance revenue to ratepayer relief and IOU programs related to energy efficiency and renewable energy, without providing any portion of the revenues to other public and private entities. Not only would this exclusive allocation be contrary to existing policy, but it would also be anti-competitive. It would be difficult for any other group to compete with the estimated $5.8 billion over eight years that IOUs are estimated to receive from revenues from Cap and Trade allowances. Local governments are legally responsible for implementing a number of local, regional, and State mandates related to land use and transportation, integrated resource management, air quality, energy efficiency codes and standards and green building practices. Ensuring that revenues from Cap and Trade are used to build on existing local government success is sound public policy, consistent with guidance from ARB. It is LGSEC's understanding that the proposed revisions to the regulation relate only to a portion of the allowance revenue. ARB should clarify that the proposed revisions relate only to the allocation of allowances to utilities, and not to the disbursement of revenue from allowance sales. Should this interpretation be incorrect, we urge that the ARB maintain the policy it adopted in December. More importantly, ARB should refrain from adopting any new regulations until the CPUC has completed its deliberations, anticipated to be in early 2012. (LGSEC2)

> **Response:** The use of allowance value and auction proceeds for allowances allocated to the electrical distribution utilities will be at the discretion of the CPUC and the governing bodies of the POUs. We believe that the regulatory language provides flexibility for the CPUC and POUs to provide funding to local governments programs if they meet the goals of AB 32.

P-14. (multiple comments)
Comment: Since utilities are managing their own auction mechanism within the program, it is appropriate for CARB to give guidance (in collaboration with CPUC) on how the allowance allocation revenue will be used. EDF supports the inclusion of the new language in section 95892(a), which offers such guidance, and ensures that ratepayers who will ultimately feel the impact of the incurred costs will be protected. (EDF4)

Comment: We urge ARB to retain the provisions in the rule providing guidance to the electric IOUs on how to return auction revenue for the benefit of their retail customers. (KUSTIN16)

> **Response:** We removed language in the regulation regarding the allowed use of proceeds from the sale of consigned allowances, since ARB does not have the authority to appropriate funds. However, we believe that the principles underlying the intent of the removed language are important. To this end, in Resolution 11-32 the Board directed the Executive Officer to work with the CPUC and publicly owned utilities to reflect the findings of the Board that the impact of the cap-and-trade regulation on electricity rates creates appropriate incentives to further the goals of AB 32. In this resolution, the Board further directed the Executive Officer to work with CPUC and publicly owned utilities to reflect the finding of the Board that if allowance value provided to the electric distribution utilities for ratepayer benefit is returned directly to customers, it is consistent with State efforts to promote energy efficiency and energy conservation. Therefore, we continue to work with the CPUC and the POU governing boards to ensure that their requirements will follow the goals of AB 32 as required in 95892(d) and ensure equal treatment to their customers.

P-15. Comment: CCSF strongly supports the guidance contained in the current proposal and believes it is critical to achieving the goals set forth by the ARB that the use of auction proceeds 1) be "used exclusively for the benefit of retail ratepayers of each electrical distribution utility;" 2) "ensure equal treatment of [the IOU's] own customers and customers of electricity service providers and community choice aggregators;" and 3) not mute the price signals that the cap and trade program is supposed to provide end users to reduce their GHG footprint. As a jurisdiction implementing community choice aggregation (CCA), CCSF is particularly concerned that the use of auction proceeds by the investor-owned utilities not unfairly disadvantage San Francisco residents and businesses that choose to take electric service from CCSF's CCA rather than the incumbent utility. Operating as an electric distribution utility that also would be subject to this guidance, CCSF believes these are reasonable conditions on the use of allowances that ensure the goals of AB 32 are achieved. Therefore, the existing requirements in the ARB's proposed Regulation should be retained. (SFMAYOR3)

> **Response:** Thank you for your support.

P-16. Comment: CCSF would like to support ARB as the appropriate enforcement entity to ensure that revenues received by electric distribution utilities from the sale of allocated allowances will benefit all of the utility's ratepayers. As a jurisdiction implementing community choice aggregation (CCA), CCSF urges ARB to ensure that allowance auction proceeds received by the investor-owned utilities are spent in a manner that does not unfairly disadvantage San Francisco residents and businesses that choose to take service from CCSF's CCA rather than the incumbent utility. (SFMAYOR3)

> **Response:** Thank you for your support. We retain the authority to revoke free allocation if it is used in a way that is counter to the requirements of the regulation and the statutory objectives of AB 32.

P-17. (multiple comments)
Comment: Praxair suggests that CARB provide greater guidance to the POUs with respect to the application of allowances to benefit their customers. Praxair is concerned that similar facilities located within different service areas—one IOU and one POU—could potentially face different economic impacts in their electricity costs due to different applications of value from the CARB allocated allowances. While true parity in the compliance burden between the different types of utilities is unlikely, potential differences to customer costs should not be exacerbated from vastly different applications of the allocated allowances. To avoid this inequitable result, CARB should specifically direct publicly owned utilities to use allowance revenue for the benefit of their customers, as independently owned utilities are required to do. (PRAXAIR2)

Comment: ARB should provide guidance to the state's POUs should they consign allowances to auction. Unlike the IOUs, the POUs will not be subject to a decision from the CPUC that will develop a framework and methodology for returning auction revenues to customers. Building on ARB's expertise and extensive examination of this issue, identifying the potential uses that ARB deems consistent with the goals of AB 32 will help steer the POUs in the right direction. (KUSTIN16)

> **Response:** Section 95892(d) of the regulation now provides the same requirements for POUs and IOUs on the limitations on the use of auction proceeds and allowance value.

P-18. (multiple comments)
Comment: We are confused by and request more definitive basis for electric ratepayer compensation in the allocation determination. Will compensation exist for both residential and commercial users? How will the compensation program work? (CIPA)

Comment: In the electricity sector, we urge you to direct utilities to protect ratepayers by returning allowance value directly to residential customers as a rebate check. Your clear statement of your intent here will assist the PUC as it deliberates how to apply this portion of the regulation to utilities. Allowing utilities to use allowance value for a vaguely-defined “ratepayer benefit” gives too much discretion to the use of billions of dollars, which is coming out of Californians pockets in the form of higher fuel and electricity prices. We urge CARB to follow recommendations from the EAAC, PUC, and CEC and regarding allocating to utilities. Any consumer rebate from utilities should not show up as a line item on electricity bills, shielding consumers from the price signal and discouraging changed behavior. The rebate must be separated from the utility bill. It should come to consumers as a “lump-sum transfer,” which could be implemented through a dividend or rebate check. The customer would still receive the carbon price signal on their utility bill, but would receive a rebate check to help buffer them from the regressive impact of increased electricity prices. We favor EAAC’s recommendations that “The largest share (roughly 75 percent) of allowance value should be returned to California households” in the form of a dividend check. The remaining 25 percent would be used for a variety of purposes including preventing leakage (a very small percent), investments in renewables and energy efficiency, and a Community Benefits Fund.

If the public receives a 75 percent dividend and utility rebate checks, they will understand that they have the ability to reduce their emissions and turn the program into a moneymaker and not a tax. This approach to revenue allocation could actually build public and political support for the implementation of this law over time. More importantly, AB 32 requires that the regulations that your board approves “ensure low income communities are not disproportionately impacted.” Without a dividend or rebate low and middle income citizens will be disproportionately impacted by increased energy prices creating an economic hardship and potential political backlash against the implementation of the law. (CPC6)

> **Response:** The allowance value given to distribution utilities must be used on behalf of ratepayers and in ways that are consistent with AB 32 statutory objectives. We acknowledge that distribution utility proceeds from the sale of allowances at auction will be subject to limitations imposed by either the CPUC or by the governing bodies of publicly owned utilities. We agree that properly structured rebates are consistent with the statutory objectives of AB 32 and could help build support for the program.

P-19. Comment: CLECA wholeheartedly agrees with CARB's statement that utility allowance auction proceeds must be used exclusively for the benefit of ratepayers. We also agree with the CARB's direction that utilities shall assure that proceeds are used in a manner which provides equal treatment of bundled and direct access customers.

CLECA includes firms that utilize bundled service and firms that take service from energy service providers under direct access. However, CLECA believes that the CARB's instruction that the use of such proceeds to provide a rate reduction or rebate to utility customers should only apply to the fixed portion of the customer bill and should not be based on usage for any period after January 1, 2012 is misguided. Not only do these restrictions make the pass-through of allowance auction proceeds to customers cumbersome to implement, and risk the possibility that some customers will receive a disproportionate share of proceeds in relation to their exposure to higher electric costs, whether higher or lower, they fail to acknowledge the fact that the rates paid by California investor-owned electric utilities currently reflect a very significant "carbon premium". CLECA submits that the proceeds should be used to soften the blow of Cap and Trade and they should be used in a way that addresses the fact that different customers will face different levels of cost increase as a result of AB 32. The implementation of Cap and Trade will increase wholesale electric costs. But, the overarching goal of reduced GHG emissions can be achieved without having to pass through in retail rates the full impact of such costs. Indeed, the benefit of Cap and Trade over a simple carbon tax is the possibility that we will be able to achieve reduced levels of GHG emissions in a more economical way, thereby benefitting the economy and each of us as residents of the State. Further, those proceeds should be passed through to ratepayers in a manner that reflects the extent of their exposure to higher electric costs. It should reflect their current usage and it should reflect the degree to which their rates are exposed to price increases resulting from Cap and Trade. Some ratepayers are currently protected from rate increases, or the full effect of rate increases, through programs such as CARE for low-income customers, or the residential inverted tier rate structure which subsidizes rates for initial volumes of usage through excess charges on higher volumes of usage. CARE customers and low usage non-CARE residential customers will not feel the full effects of Cap and Trade on their electric rates and they should not receive a full share of allowance auction proceeds through "per capita" or "per ratepayer" rebates. (CLECA)

> **Response:** Proper carbon pricing is the primary way in which the cap-and-trade program achieves emissions reductions. We believe that carbon price signals in electricity rates should reflect the emissions rate of the marginal generator dispatched into the power markets. In establishing the appropriate carbon price in rates, the CPUC and POU governing boards will need to account for the current rate structure limitations (including the CARE program) and the impact of other GHG-reducing policies, including the 33 percent renewable portfolio standard on electric rates. We support providing benefits to residential ratepayers such that the compensation serves to reward those that choose low-carbon electricity services, including green power pricing programs, while discouraging high carbon choices.

P-20. Comment: We strongly support ARB's modification of the rule to ensure there is transparency with respect to both the amount and distribution of allowance value allocated to the State's utilities, including California's publicly-owned utilities (POU). ARB designed the allocation scheme for the utility sector to mitigate the bill impacts of the program on retail electricity customers by returning allowance value through retail electricity providers. While the rule is clear that allowance value must be used for the exclusive benefit of customers, adding reporting provisions will enable ARB to assess more effectively whether and how the utilities are fulfilling this obligation. (KUSTIN16)

> **Response:** The use of allowance value and auction proceeds must be reported annually to us. The provisions are listed in 95892(e). The utilities must state how the allowance value and auction proceeds were used to meet the goals laid out in AB32 to benefit their ratepayers.

P-21. Comment: PG&E believes that electric utilities are uniquely positioned to return allowance value to customers because they are subject to state utility commission or board oversight. In fact, PG&E is already working with the CPUC to determine the method for returning allowance value. PG&E will continue to oppose any proposals to allocate allowances to generators, which have neither the necessary regulatory oversight nor the established relationship with customers that would ensure that all utility customers receive the full benefit of allowance revenue. PG&E supports the aforementioned elements of ARB's allocation proposal, as they appropriately recognize the role that electric utility customers will have in meeting AB 32 goals. (PGE4)

> **Response:** We appreciate PG&E's support of the allocation methodology and acknowledge the CPUC's process to determine how allowance value should be used by the IOUs. We do not currently plan to allocate allowances to electricity generators.

P-22. Comment: PG&E understands that ARB intends to return allowance value to the electric distribution utility, including bundled utility customers, along with community choice aggregation customers, direct access customers, and other electricity service provider customers. PG&E suggests that ARB add language to Appendix A clarifying the intent to include all utility customers. (PGE4)

> **Response:** The regulatory process does not include making changes in Appendix A to the First 15-Day Change Notice.

P-23. Comment: CARB should defer to CPUC as to the dispensation of the funds that the IOU's receive from monetizing their emissions allocations. CPUC is the agency charged with protecting ratepayers, not CARB. All of the funds should be refunded back to all classes of ratepayers and not diverted to fund solar, wind, or environmental justice community projects. The same concept should apply when natural gas is brought into the Cap and Trade system. Despite assurances from CARB, there exists real concern that non-regulated entities will game the system. CARB should initiate at least one dry run before the first auction. With a system as complex as this, the stakes for entities required to participate are high. (CALFP3)

> **Response:** The use of allowance value and auction proceeds for allowances allocated to the electrical distribution utilities will be determined by the CPUC and

the governing bodies of the POUs. We will continue to work with these entities to ensure that allocation of allowance value to ratepayers creates proper incentives. The regulation does not allocate funds to natural gas utilities for the benefit of ratepayers.

V. SUMMARY OF COMMENTS MADE DURING THE SECOND 15-DAY COMMENT PERIOD AND RESPONSES

The table below identifies the comments received during the second 15-day comment period. Despite falling outside the scope of the second 15-Day Change Notice, a number of comments nevertheless are summarized and responded to below. Although ARB legally is not required to summarize and respond to these comments under the APA, we provided a response to these comments because it was felt the general public and interested stakeholders could benefit from the additional clarity provided by the responses.

A. LIST OF COMMENTERS

Table V-1: Comments Received During the Second 15-Day Comment Period

Abbreviation	Commenter
3DEGREES3	Ian McGowan, 3Degrees Written Testimony: 9/27/2011
AB32IG3	Shelly Sullivan, AB 32 Implementation Group Written Testimony: 9/27/2011
ACC5	Emily Rooney, Agricultural Council of California Written Testimony: 9/27/2011
ACERIO2	Maggie Estrada, ACE Cogeneration and Rio Bravo Written Testimony: 9/27/2011
ALLI2	Dwayne Phillips, Air Liquide Large Industries U.S. LP Written Testimony: 9/27/2010
APC3	Keith Adams, P.E., Air Products and Chemicals Written Testimony: 9/27/2011 **In addition, 2 supplemental documents were submitted**
BAC	Catherine Lyons, Bay Area Council Written Testimony: 9/27/2011
BBM	Bruce McLaughlin, Braun Blaising McLaughlin, P.C. Written Testimony: 9/27/2011
BCFSE2	Lisa Jacobson, Business Council for Sustainable Energy Written Testimony: 9/27/2011
BGCEBS	Josh Margolis, BGC Environmental Brokerage Services, L.P. Written Testimony: 9/27/2011
BLUESOURCE3	Jeff Cole, Blue Source Written Testimony: 9/27/2011
BONNEVILLEPWR3	Courtney Olive, Bonneville Power Administration Written Testimony: 9/20/2011

CACC3	Beth Vaughan, California Cogeneration Council Written Testimony: 9/27/2011
CAISO	Keith E. Casey, PhD, California Independent System Operator Corporation Written Testimony: 9/27/2011
CALCHAMBER4	Brenda Coleman, California Chamber of Commerce Written Testimony: 9/27/2011
CALFP4	John Larrea, California League of Food Processors Written Testimony: 9/27/2011
CALPINE4	Kassandra Gough, Calpine Corporation Written Testimony: 9/27/2011
CAR5	Gary Gero, Climate Action Reserve Written Testimony: 9/27/2011
CBD5	Brian Nowicki and Kevin Bundy, Center for Biological Diversity Written Testimony: 9/27/2011 **In addition, 3 supplemental documents were submitted**
CBE3	Julia May, Communities for a Better Environment Written Testimony: 9/27/2011 **In addition, 2 supplemental documents were submitted**
CBE4	Greg Karras and Adrienne Bloch, Communities for a Better Environment Written Testimony: 9/27/2011 **In addition, 2 supplemental documents were submitted**
CCEEB4	Robert W. Lucas and Gerald D. Secundy, California Council for Environmental and Economic Balance Written Testimony: 9/27/2011
CE2CC2	Harold Buchanan, CE2 Carbon Capital Written Testimony: 9/27/2011
CEERT2	Danielle Osborne Mills, Center For Energy Efficiency And Renewable Technologies Oral Testimony: 9/27/2011
CERP5	Kyle Danish, Coalition for Emission Reduction Policy Written Testimony: 9/27/2011
CFA3	Steven Brink, The California Forestry Association Written Testimony: 9/26/2011
CHEVRON4	Stephen Burns, Chevron Written Testimony: 9/27/2011
CHEVRON5	Jean-Philippe Brisson and Stan Renas, Linklaters, P.C. for Chevron Written Testimony: 9/27/2011
CIG3	Charles Purshouse, Camco International Group, Inc. Written Testimony: 8/11/2011

CIPA2	Norman Plotkin, California Independent Petroleum Association Written Testimony: 9/27/2011
CONOCO3	Chris Chandler, ConocoPhillips Company Written Testimony: 9/27/2011
COVANTA2	Ellie Booth, Covanta Energy Written Testimony: 9/27/2011
CPC7	Barry Vesser, Climate Protection Campaign Written Testimony: 9/27/2011
CRS3	Jennifer Martin, Center for Resource Solutions Written Testimony: 9/27/2011
CSCME5	John Bloom, Coalition for Sustainable Cement Manufacturing and Environment Written Testimony: 9/22/2011
CWCCG	Zeynep Erdal, PhD, PE, California Wastewater Climate Change Group Written Testimony: 9/26/2011
DWR3	Veronica Hicks, Department of Water Resources Written Testimony: 9/27/2011
EDF6	Tim O'Connor, Environmental Defense Fund Written Testimony: 9/27/2011
EOSC4	Jeff Cohen, EOS Climate Written Testimony: 9/27/2011
EVMKTS3	Lenny Hochschild, Evolution Markets Inc. Written Testimony: 9/27/2011
FINITE2	Sean Carney, Finite Carbon Corporation Written Testimony: 9/27/2011
FORMLETTER13	Doug Murray ** 5 additional commenters submitted similar comments ** Written Testimony: 9/16/2011
GA2	Michael Gardner, Gypsum Association Written Testimony: 9/26/2011
GEAG2	Jeffrey Fort, GHG Early Action Group Written Testimony: 9/27/2011
GLASSPI	Lynn Bragg, Glass Packaging Institute Written Testimony: 9/27/2011 **In addition, 1 supplemental document was submitted**
GREENX2	John Melby, Green Exchange Written Testimony: 9/27/2011
IBERDROLA2	Laura Beane, Iberdrola Renewables Written Testimony: 9/27/2011

IEPA3	Steven Kelly and Amber Riesenhuber, Independent Energy Producers Association Written Testimony: 9/27/2011
IETA4	Henry Derwent, International Emissions Trading Association Written Testimony: 9/27/2011
IGPACC2	Rob Simon, The Industrial Gases Panel of the American Chemistry Council Written Testimony: 9/27/2011
KUSTIN17	Camille Kustin, Better World Group for Andy Katz, Breathe California; Susan Stephenson, California Interfaith Power and Light; Jennifer Martin, Center for Resource Solutions; Peter Miller, Natural Resources Defense Council; Laura Wisland, Union of Concerned Scientists Written Testimony: 9/2/2011
KUSTIN18	Camille Kustin, Better World Group for Bonnie Holmes-Gen, American Lung Association in California; Andy Katz, Breathe California; Brian Nowicki, Center for Biological Diversity; Barry Vesser, Climate Protection Campaign; Shankar Prasad, Coalition for Clean Air; Tyson Eckerle, Energy Independence Now; Ryan Young, Greenlining Institute; Diane Bailey, Natural Resources Defense Council; Kathryn Phillips, Sierra Club California; Jasmin Ansar, Union of Concerned Scientist Written Testimony: 9/27/2011
KUSTIN19	Camille Kustin, Better World Group for Jennifer Martin, Center for Resource Solutions; Barry Vesser, Climate Protection Campaign; Shankar Prasad, Coalition for Clean Air; Ryan Young, Greenlining Institute; Alex Jackson, Kristin Eberhard and Peter Miller, Natural Resources Defense Council; Jasmin Ansar, Union of Concerned Scientists Written Testimony: 9/27/2011
LADWP5	Lorraine Paskett, Los Angeles Department of Water and Power Written Testimony: 9/27/2011
LASD4	Stephen R. Maguin, Sanitation Districts of Los Angeles County Written Testimony: 9/23/2011
LASD5	Stephen R. Maguin and Frank R. Caponi, Los Angeles County Sanitation Districts Written Testimony: 9/27/2011

LGCRE3	John Holladay, Local Government Coalition for Renewable Energy Written Testimony: 9/27/2011
LSPOWER2	Jennifer Chamberlin, LS Power Written Testimony: 9/27/2011
MCAGCC	Erin Adams, Marine Corps Air-Ground Combat Center, Twentynine Palms Written Testimony: 9/27/2011
MID4	Joy Warren, Modesto Irrigation District; Elizabeth Hadley, Redding Electric Utility; Dan Severson, Turlock Irrigation District Written Testimony: 9/27/2011
MSCG4	Steve Huhman, Morgan Stanley Capital Group, Inc. Written Testimony: 9/27/2011
MSR2	Martin Hooper, M-S-R Public Power Agency Written Testimony: 9/27/2011
MWDSC4	Jeffrey Kightlinger, The Metropolitan Water District of Southern California Written Testimony: 9/27/2011
NAES2	Thomas Corr, Greg Bass and Justin Pannu, Noble Americas Energy Solutions Written Testimony: 9/27/2011
NC9	Michelle Passero, The Nature Conservancy Oral Testimony: 9/27/2011
NCPA4	Susie Berlin, McCarthy & Berlin, P.C. for Northern California Power Agency Written Testimony: 9/27/2011
NEWFOREST3	Brian Shillinglaw, New Forests Written Testimony: 9/27/2011
NEXTERAENERGY3	Kyle Boudreaux, NextEra Energy Resources Written Testimony: 9/27/2011
OFFSETSWG4	Bruce McLaughlin, Offsets Working Group for Joy Warren, Modesto Irrigation District; Elizabeth Hadley, City of Redding; Michael Bloom, City of Roseville; Timothy Tutt, Sacramento Municipal Utility District; Dan Severson, Turlock Irrigation District Written Testimony: 9/27/2011
OPC3	Carl Wirdak, Occidental Petroleum Corporation Written Testimony: 9/27/2011
PACIFICOR4	James Campbell, PacifiCorp Written Testimony: 9/27/2011

PEBI2	Michael Mazowita, P.E. Berkeley, Inc.; Sean P. Lane, Olympus Power, LLC Written Testimony: 9/27/2011
PEC2	Don Burkard, Panoche Energy Center Written Testimony: 9/23/2011
PFT4	Paula Swedeen, The Pacific Forest Trust Written Testimony: 9/27/2011
PGE5	John W. Busterud, Pacific Gas and Electric Company Written Testimony: 9/27/2011
PGPPC2	William Sims, Procter & Gamble Paper Products Company Written Testimony: 9/27/2011
POWEREX2	Nicholas W. van Aelstyn, Beveridge & Diamond, P.C. for Powerex Corp Written Testimony: 9/27/2011
PPGI2	Ray Yee, PPG Industries Written Testimony: 9/27/2011
PRAXAIR3	Gerald Miller, Praxair Inc. Written Testimony: 9/27/2011
REMA3	Josh Lieberman, Renewable Energy Markets Association Written Testimony: 9/27/2011
RSI	Charles Helget for Anthony M. Pelletier, Republic Services, Inc. Written Testimony: 9/29/2011
SCAQMD5	Barry Wallerstein, South Coast Air Quality Management District Written Testimony: 9/27/2011
SCE4	Jennifer Tsao Shigekawa and Nancy Chung Allred, Southern California Edison Company Written Testimony: 9/27/2011
SCPPA8	Norman Pederson, Southern California Public Power Authority Written Testimony: 9/27/2011
SEMPRA4	Eugene Mitchell, Southern California Gas Company, San Diego Gas & Electric Company, Sempra Energy Utilities Written Testimony: 9/27/2011
SHELLENERGY2	Marcie Milner, Shell Energy North America Written Testimony: 9/27/2011
SMITHS2	Steven B. Smith, Verallia Written Testimony: 9/27/2011
SMUD4	William Westerfield III, Obadiah Bartholomy, and Timothy Tutt, Sacramento Municipal Utility District Written Testimony: 9/27/2011

SPM	JJ Fair, Starwood Power Midway, LLC Written Testimony: 9/27/2011
SWC4	Terry Erlewine, State Water Contractors Written Testimony: 9/27/2011
TCF3	Chris Kelly, The Conservation Fund Written Testimony: 9/27/2011
TCT2	Sheldon Zakreski, The Climate Trust Written Testimony: 9/27/2011
TESORO3	Daniel Riley, Tesoro Companies, Inc. Written Testimony: 9/27/2011
TFI2	William Herz, The Fertilizer Institute Written Testimony: 9/27/2011
TI2	Carole J. Stapper, Temple-Inland Written Testimony: 9/27/2011
TPI6	Erin Craig, TerraPass Inc. Written Testimony: 9/27/2011
TSG	Annika Muenkel, TschachSolutions GmbH Written Testimony: 9/27/2011
TWS2	Ann Chan, The Wilderness Society Written Testimony: 9/27/2011 **In addition, 2 supplemental documents were submitted**
UC4	Nathan Brostrom, University of California Written Testimony: 9/23/2011
UCB3	William Stewart, University of California Berkeley Written Testimony: 9/16/2011
UCS8	Jasmin Ansar and Dan Kalb, Union of Concerned Scientists Written Testimony: 9/26/2011 **In addition, 1 supplemental document was submitted**

UCS9	Mirriam Swaffer, Union of Concerned Scientists for Norris McDonald, African American Environmentalist Association; Bonnie Holmes-Gen, American Lung Association in California; Andy Katz, Breathe California; Susan Stephenson, California Interfaith Power and Light; Nancy Rader, California Wind Energy Association; Nick Lapis, Californians Against Waste; Betsy Reifsnider, Catholic Charities, Diocese of Stockton; Brian Nowicki, Center for Biological Diversity; Jane Valentino, Center for Resource Solutions; James J. Provenzano, Clean Air Now; Ann Hancock, Climate Protection Campaign; Shankar Prasad, Coalition for Clean Air; Katie DeCarlo, Ella Baker Center for Human Rights; Tyson Eckerle, Energy Independence Now; Mary Luevano, Global Green USA; Ryan Young, The Greenlining Institute; Katy Yan, International Rivers; Kevin Hamilton, Medical Advocates for Healthy Air; Ron Sundergill, National Parks Conservation Association; Matthew Marsom, Center for Public Health and Climate Change Public Health Institute; Anne Kelsey Lamb, Regional Asthma Management and Prevention; Kathryn Phillips, Sierra Club California; Daniel Kalb, Union of Concerned Scientists Written Testimony: 9/27/2011
UNITEDAIRLINES3	Jimmy Samartzis, United Airlines Written Testimony: 9/27/2011
UOV	Andrew J. Weaver, University of Victoria School of Earth and Ocean Sciences Climate Group Written Testimony: 9/26/2011
USDOD3	C.L. Stathos, United States Department of Defense Written Testimony: 9/27/2011
USDON	Jackalyne Pfannenstiel, United States Department of the Navy Written Testimony: 9/27/2011
USW	Robert LaVenture, United Steel Workers Written Testimony: 9/27/2011
VALERO3	Patrick Covert, Valero Written Testimony: 9/23/2011
VCSA2	David Antonioli, Verified Carbon Standard Association Written Testimony: 9/27/2011
WAPA3	Koji Kawamura, Western Area Power Administration Written Testimony: 9/22/2011
WEC3	Doug Davie, Wellhead Electric Company Written Testimony: 9/29/2011

WILDFLOWER	Bo Buchynsky, Wildflower Energy LP Written Testimony: 9/27/2011
WILLIAMSZ3	Laurie Williams and Allan Zabel Written Testimony: 9/27/2011
WILLIAMSZ4	Laurie Williams and Allan Zabel Written Testimony: 9/27/2011
WIRA4	Craig Moyer, Western Independent Refiners Association Written Testimony: 9/26/2011
WM4	Charles White, Waste Management Written Testimony: 9/27/2011
WPTF3	Clare Breidenich, Western Power Trading Forum Written Testimony: 9/27/2011
WSPA4	Catherine Reheis-Boyd, Western States Petroleum Association Written Testimony: 9/27/2011

B. AB 32/CAP-AND-TRADE DESIGN

Emissions Levels/Targets/Forecasts

B-1. Comment: To reiterate our previously filed comments, we are opposed to CARB continuing on the path of adoption of the cap and trade program. As noted previously, while CIPA began the climate change policy journey with a position that market mechanisms most efficiently provide for compliance flexibility, the evolution of our position has been influenced by two irrefutable factors. First are the emissions numbers. The Legislative Analyst's Office has covered quite comprehensively, and we have previously detailed, that enough activity has been undertaken—numerous programs and policies put into place that coupled with dramatically reduced economic output have allowed us to achieve, or at least establish the glide path to the emission reduction targets envisioned by the framers of AB 32. Second, we look at the market design features of the currently proposed program and inherently understand that no matter how well intentioned they portend disaster for the economy as a whole and regulated entities specifically. We note that a market based system is permissive and not mandated under AB 32. Health and Safety Code section 38570 reads in part: 38570. (a) The state board may include in the regulations adopted pursuant to section 38562 the use of market-based compliance mechanisms to comply with the regulations (emphasis added). CIPA asserts, again, that CARB has met all of the emissions targets required by AB 32 and need only eliminate cap and trade from the current policy mix to arrive at a combined strategies alternative that satisfies AB 32 and does not set us up for a rerun of the terrible crisis the state experienced the last time it embarked upon an untested and ill-conceived Rube Goldberg policy regime. (CIPA2)

> **Response:** The comment falls outside the scope of the second 15-day changes to the regulation. No response is necessary. Please see responses in Chapters III and IV, in sections B and F.

General

B-2. Comment: This regulation places many requirements on regulated entities, which must be able to plan for and comply within a timely manner. Entities will be unable to do so without the necessary enabling compliance tools, guidance, and infrastructure in place from the onset of this regulation. Delays and uncertainties will unnecessarily increase costs and exposure to violations. CCEEB appreciates the 2013 start date and believes this should help implementation of this regulation. ARB should clearly announce the full schedule from now to the end of this rulemaking in October 2011 and outline the additional rulemakings and amendment topics that will take place through 2012. CCEEB recommends that:

- ARB develop a work plan with a clear lists of tools, guidance, policies, trainings, and systems that they must develop, along with completion deadlines for each activity that must be in place for the regulated entities to comply. This should include the timeline for the 45-day changes in the future that will be needed prior to the launch of the market.

- ARB include a mechanism that links an entity's compliance deadlines directly to availability of theses compliance tools, allowing for sufficient lead time for facility compliance. (CCEEB4)

  Response: The comment falls outside the scope of the second 15-day changes to the regulation. Nevertheless, we will provide tools and guidance to help covered entities understand and comply with the regulation. Moreover, we will consider using tools, such as guidance documents during implementation, to help covered entities comply with the regulation.

B-3. Comment: We urge ARB to ensure that the infrastructure and programs necessary to support the objectives and requirements of a cap-and-trade program are fully developed before adopting a final rule. (VALERO3)

> **Response:** We believe that the necessary infrastructure and programs will be in place, and we adjusted the compliance start date from 2012 to 2013 to ensure that all the regulatory elements are fully functional. We initiated activities to develop the necessary rule implementation infrastructure for the regulation, including a market tracking program to trade allowances and offsets; contracts for an auction services provider; a financial services provider; and a market monitor. We are also committed to providing updates to the Board on the implementation of the regulation.

B-4. Comment: CalChamber is disappointed to see that the Board addressed nearly none of the concerns raised in our previous comment letter dated August 11, 2011. The comments submitted expressed concern for the current design of the program and recommended modifications that are vital to ensuring an operable, cost-effective market designed to meet the GHG emission goals of AB 32. Without the recommended changes, the cap-and-trade regulation remains incomplete, and lacks the confidence and certainty needed toward successful implementation. (CALCHAMBER4)

> **Response:** The comment is outside the scope of the second 15-day changes to the regulation. However, any comments submitted in the August 11, 2011, letter that were within the scope of the first 15-day changes to the regulation were summarized, and responses were provided in Chapter IV “Summary of Comments Made During the First 15-Day Comment Period and Responses.”

B-5. (multiple comments)
Comment: Design aspects of EU carbon trading, which caused bad results in Europe are being replicated in the current California cap and trade proposal, including allowing banking credits, resulting in less progress in later years; free allocations, overallocation, and offsets, allowing industries to escape reductions; failure to account for swamping of reductions through high-carbon imports (a different kind of leakage of emissions into instead of out of the system); and taking credit for reductions caused only by economy crashes. (CBE3)

Comment: California's Draft Regulation replicates the failed design elements of European carbon trading. CARB's assumption that the EU-ETS is working is wrong, and this fact challenges CARB's basis for replicating that program's features. First, the European program did not make good progress over time. An International Energy Agency report found emissions and energy use started high in 2005 compared to 1990 levels. European CO_2 emissions increased in 2007 and carbon credits were effectively free. Second, the EU-ETS has created perverse incentives and resulted in dubious projects. EU offsets were massively abused, caused perverse incentives, and could cause increased emissions. Both these conditions are present in the proposed California cap and trade regulation. For example, CARB provides 100 percent free allocation for oil drilling operations through 2020, and gives 10 times more allocations for higher-pollution types of drilling. Oil refineries receive mostly free allocations (about 72 percent total over the eight years from 2013-2020) and are proposed to use the distorted Solomon index, which favors more energy-intensive refinery processes. There are dozens of reports, papers, and articles available showing the failure of the design elements of carbon trading. CBE provided other evidence about this in our July comments on the Scoping Plan. Many others have documented these problems. The continued march toward this program in California is at this point disgraceful. At the same time as the EU-ETS provided windfall profits for companies, it increased costs for the public. BTI Europe found that the EU emissions went up, and still cost the public 100 billion. CARB is doggedly counting on the same regulatory structure to get different results. There is no reason to believe that California's market will perform any better, especially since the same traders and bankers will be involved. (CBE3)

> **Response:** This comment falls outside the scope of the second 15-day changes to the regulation. Nevertheless, steps will be taken to carefully monitor industry progress toward compliance with the regulation, as well as the operation of the markets, to avoid the issues that were experienced in Europe.
>
> As specified in Board Resolution 10-42, the Board directed the Executive Officer (EO) to hold public consultations to identify potential obstacles to compliance and, as necessary, incorporate or enhance compliance assistance mechanisms into the program. The Board also directed the EO to contract with an independent entity with appropriate expertise to monitor and provide public reports on the market's operation, including auctions and reserve sales, on a quarterly basis and recommend appropriate action, which could include taking corrective action prior to the next auction, adding future allowances to the allowance reserve or future auctions, or temporarily suspending trading in the market. We have released a Request for Proposal for the market monitor.
>
> We had reported data and third-party verified emission data to use when designing the program; therefore, based on the data, we will not overallocate allowances, thus avoiding windfall profits. We have addressed leakage by using an updating output-based allocation system for industrial producers . In addition, the requirement to use allowance value for investor-owned or publically owned utilities is designed to avoid providing windfall profits in the electricity sector (as

happened in the EU). Lastly, the commenter asserts that the EU took "credit for reductions caused only by economy crashes." The cap-and-trade program is designed to limit overall emissions for those covered by the program. Reductions occur as a result of the declining emissions limit. If the demand for energy, which creates emissions, is reduced as a result of lower economic activity, the program goals are met with lower allowance prices. The cap-and-trade program responds automatically to changes in economic activity while ensuring environmental protection.

District Role

B-6. (multiple comments)
Comment: Once implemented, this program requires extensive oversight by CARB not only to monitor emissions from many entities' intrinsic operations, but also to provide oversight to other participants such as verifiers, project developers, registries, account holders, and brokers, whose motives are not solely for the benefit of this program. Having other public agencies such as air districts participate further will strengthen the intended results and co-benefits of this program while helping alleviate some of the oversight burden. (SCAQMD5)

Comment: SCAQMD's and CAPCOA's previous comment letters on draft versions of the Cap and Trade regulation outlined areas in which Air Districts should be allowed to participate with multiple roles. To date, several of the suggested changes allowing air districts to participate with multiple roles have not been accommodated, nor have discussions between CAPCOA and CARB occurred as directed in Resolution 10-42. We would still like to have discussions facilitated by CARB with CAPCOA to outline how Air Districts may participate and accommodate the implementation of the Cap and Trade program. (SCAQMD5)

Response: As discussed in Board Resolution 11-32, we will partner with the local air districts in the implementation of the cap-and-trade program. We are continuing dialogue with the air districts to better define their roles with implementation of the regulation. We believe this will accomplish the goal of having the air districts participate in multiple roles, including participation in greenhouse gas permitting and Adaptive Management Plan implementation.

Working Group/Advisory Group

B-7. (multiple comments)
Comment: The AB 32 Implementation Group supports and encourages a stakeholder advisory committee to provide continual and thoughtful feedback to CARB as the program rolls out during the next few years. (CALFP4)

Comment: The AB 32 Implementation Group supports and encourages a stakeholder advisory committee to provide continual and thoughtful feedback to CARB as the program rolls out during the next few years. (AB32IG3)

Response: These comments fall outside the scope of the second 15-day changes to the regulation. Nevertheless, as stated in the responses in the first 15-day comments to the regulation, we do not see the need for the specific stakeholder committees or working groups suggested by the commenters. As specified in Board Resolution 10-42 for the original regulation, the Board directed the EO to hold public consultations to identify potential obstacles to compliance with the regulation.

Public Process

B-8. (multiple comments)
Comment: Regarding the CARB process, as the deadline for submitting the rule to the Office of Administrative Law approaches, CLFP believes it is necessary to express our dismay regarding the 15-day update process and the prospect for further rule changes and updates next year. This rule is extremely complex and it will have a large impact on the California economy. It should be incumbent upon CARB to conduct additional workshops and provide more time for the public to provide feedback, as well as for the staff to hear and incorporate reasonable changes to the rule. Fifteen days for written comment is insufficient for a rule of this magnitude. CLFP urges CARB to adopt a more robust public process going forward. Getting it right is more important than meeting a deadline dreamed up by a dysfunctional political process. (CALFP4)

Comment: WIRA recognizes and appreciates the difficulty and obstacles that arose during this adoption process that CARB staff had to overcome, but in adopting such a complex and important regulation, public process is key. We have already noted that any additional changes to the Cap and Trade Regulation based on this open comment period cannot occur during this specific rulemaking. WIRA urges CARB not only to respond to these comments now, but also to use them as the basis and starting point for the inevitable first round of regulatory adjustments to the program. (WIRA4)

Comment: Valero is concerned that ARB has not addressed all stakeholder comments submitted during the previous comment period. In addition, we believe that the proposed regulation, as written, provides an incomplete rulemaking package. Valero strongly urges ARB to fully evaluate the merits of comments submitted in both the first and second public comment periods to ensure a thorough regulatory development process prior to adoption of any cap-and-trade regulation. (VALERO3)

Comment: Gaps and inconsistencies between the Cap-and-Trade program and the MRR remain and could threaten the long-term success of the programs. Powerex encourages ARB to include in its resolutions adopting the rules a directive to ARB staff to continue vetting these important issues through a regulatory refinement process that includes stakeholder workshops. Such a directive, which could be modeled upon Resolution 10-42, should direct the ARB Executive Officer to prepare additional 15-day rule modifications which then would form the basis of amendments to the rules that then could be adopted by the Board in 2012 prior to the Cap-and-Trade Rule's full implementation in 2013. Powerex also requests that ARB utilize the 2012 period to develop detailed guidance documents to clarify many of the issues in the rules that remain ambiguous. These additional steps would not interfere with adoption of the modified rules in October, but would ensure that ARB staff has full authority to continue its work on refining the program prior to its full implementation in 2013. (POWEREX2)

Comment: As we come closer to the deadline for submitting the rule to the Office of Administrative Law, we want to express our concern about the 15-day comment process and the need for further rule changes and updates next year. The rule is extremely complex and it will have a large impact on the California economy. In that regard, we would request the California Air Resources Board (CARB) include in the Final Statement of Reasons (FSOR) a schedule by which workshops and needed revisions will occur so the public can schedule and provide feedback in order for the staff to hear and incorporate reasonable changes to the rule. (AB32IG3)

> **Response:** The rulemaking process provided ample opportunity for input from interested stakeholders and the public. The notices for the first and second 15-day changes to the regulation were posted on the ARB website, and were followed by an email list serve notice that provided a link to submit public comments on regulatory changes.
>
> On July 15, 2011, we held a public workshop to discuss the first 15-day changes to the regulation and to seek additional input for the second 15-day changes to the regulation. We also released a discussion draft that was the subject of the July 15th workshop. The format of the workshop included an informal interaction among stakeholders and ARB staff. The workshop was also available via webcast. In addition, we maintained a public meetings web page, where we made available all workshop materials. In addition, on August 26, 2011, we held a technical team meeting discussing topics related to electricity and GHG emission reporting.
>
> By way of this FSOR document, we prepared written responses to all public comments received during the initial 45-day comment period; comments presented at the December 16, 2010, Board hearing, both orally and in writing; and comments received during the first 15-day changes to the regulation and the second 15-day changes to the regulation. The Administrative Procedure Act (APA) only requires that ARB respond to changes that are noticed.
>
> We will provide tools and guidance to help covered entities understand and comply with the regulation. Moreover, we will consider using tools, such as guidance documents during implementation, to help covered entities comply with the regulation.

Implementation

B-9. (multiple comments)
Comment: As with any new regulatory program, some "learning by doing" will be embedded into the cap-and-trade implementation process. However, EDF believes the regulation as written meets the goals and objectives of AB 32 and will stimulate the development of innovative emissions reductions projects and technologies. We look forward to working with CARB and other stakeholders throughout California in these ongoing efforts. (EDF6)

Comment: Delaying the implementation of the cap-and-trade component of AB 32 would not only jeopardize California's goals to tackle global climate change but would also introduce market uncertainty that undermines an engine to create innovation, investments and jobs in California. Although emissions obligations are not in effect until January 2013, major components of AB 32 were to be implemented in January 1, 2012. The Bay Area Council supports pushing ahead on implementation of the re-approved AB 32 Scoping Plan to get California on track in solving global climate change and keep investments, innovations and jobs in the clean energy sector within our State. (BAC)

> **Response:** We appreciate the support. As stated in the responses to the 45-day public notice, the compliance start date was moved from 2012 to 2013 to ensure that all the regulatory elements are in place and fully functional. We initiated activities to develop the necessary rule implementation infrastructure for the regulation, including a market tracking program to trade allowances and offsets; contracts for an auction services provider; a financial services provider; and a market monitor. We are also committed to providing continual public updates, with opportunity for stakeholder comment, on the implementation of the regulation.

Program Monitoring

B-10. (multiple comments)
Comment: EDF views the development of strong and transparent guidance documents relating to program enforcement and offset evaluation as an important effort that should be pursued as soon as possible. While procedures and guidance for compliance and enforcement will necessarily be based on implementation of the regulatory wording, ensuring regulated entities and project developers understand the way in which the regulation is applied, (and in particular, where CARB has discretionary authority), is important to maximize certainty and assist financial decision making. (EDF5)

Comment: A periodic review of the cap-and-trade program is critical to ensure GHG reductions are achieved while maintaining the competitiveness of California businesses and the health of the economy. (CALCHAMBER4)

Comment: Adopting and setting the cap-and-trade regulation in motion does not signify the end of the regulatory process. To make sure the program is performing as planned and to enable CARB to respond to unwanted conditions that may arise, effective programmatic review must be a part of the regulatory agenda, both during the first compliance period and following periods. To achieve public support and overall integrity, reviews should be built on sound scientific data and observations of market activity, and be completed in a transparent, public process. EDF encourages CARB remain committed to the following important efforts:

- Performing periodic reviews of existing and future offset protocols;
- Continuously performing reviews of market operations to assess leakage and guard against windfall profits—leading to a thorough evaluation of the appropriateness of the current allocation formulas in future compliance periods;
- Developing a new refinery allocation formula, based on information developed during ongoing and planned research efforts, for use starting in the second compliance period. (EDF6)

  Response: These comments fall outside the scope of the second 15-day changes to the regulation. However, we are committed to regular reviews of the implementation of the regulation, periodic updates to the Board, and proposed modifications to the regulation, as needed. As discussed in Resolution 10-42 and 11-32, the Board directed the Executive Officer to update the Board at least annually on the status of the cap-and-trade program. In addition, we will provide tools and guidance to help covered entities understand and comply with the regulation. Moreover, we will consider using tools, such as guidance documents during implementation, to help covered entities comply with the regulation.

B-11. (multiple comments)
Comment: It is imperative that the State monitor leading indicators that reflect the economic health of California. California must be positioned to identify any potential problems that may be inadvertently caused by this regulation, before they cause significant damage to the economy so that any regulatory structural problems can be corrected in a timely manner. CCEEB recommends that the ARB include provisions in the cap-and-trade regulation to:

- Monitor specific economic indicators, including the price in the auctions, the functioning of secondary markets, adequacy of the Allowance Price Containment Reserve, detection of market manipulation, offset supply, evidence of contract shuffling, progress towards achieving the 2020 target, total cost of the program, jobs in manufacturing, vacancy rates, home sales, volume of trade through ports, Gross State Product, energy prices, and other indicators used by the Department of Finance to monitor the health of California's economy;
- Establish criteria and process to be used to determine the need and amend the regulations;
- Establish formal reviews of the regulation at least once each compliance period; and
- Develop and implement a more structured process and approach for evaluating the comparative cost-effectiveness of program measures, as well as the relative

cost-effectiveness of those measures vis-a-vis the cap-and-trade program and identify any potential problems. (CCEEB4)

Comment: We understood that ARB expects to incorporate, into the regulation, specific requirements for a review of the program at least once every compliance period in the ISOR. However, there are no references to this proposal in the actual regulation. We also understand that ARB intends to use "adaptive management" as an element in review of the program to identify and mitigate adverse impacts of the program, and help develop any additional improvements or changes necessary to this regulation. WSPA believes that in order to ensure that the changes can be made in a timely manner and that the obligated entities are provided certainty, ARB should identify leading indicators that should be monitored for the economic and energy health of California and criteria for changes to the program, before the program begins. Staff proposes to incorporate into the regulation specific requirements for a review of the program at least once every compliance period. The new regulatory text will include specific deadlines for completion of the review, a list of topics that must be addressed in the review, and minimum requirements for public input during the review process. We recommend that ARB identify the leading indicators of California's economic and energy health that should be monitored routinely and specify the criteria that will drive any changes to the program. Moreover, ARB should specify that any review of the cap and trade regulation shall occur at least once every compliance period. If revisions are needed, they should be completed no later than one year before the start of the next compliance period to allow sufficient time for compliance by program participants. (WSPA4)

Response: These comments fall outside the scope of the second 15-day changes to the regulation. However, we are committed to regular reviews of the implementation of the regulation with opportunity for stakeholder comment, periodic updates to the Board, and proposed modifications to the regulation, as needed. As discussed in Resolution 10-42 and 11-32, the Board directed the Executive Officer to update the Board at least annually on the status of the cap-and-trade program. In addition, we will provide tools and guidance to help covered entities understand and comply with the regulation. Moreover, we will consider using tools, such as guidance documents during implementation, to help covered entities comply with the regulation.

Adaptive Management

B-12. Comment: EDF encourages CARB remain committed to the following important efforts: Adaptively managing the program for unwanted indirect environmental impacts. (EDF6)

Response: In Resolution 11-32, the Board approved an Adaptive Management Plan. This plan will monitor for potential adverse environmental impacts associated with potential localized air quality impacts and the U.S. forest offset protocol.

The adaptive management approach will allow us to collect and review applicable data sources (i.e., the MRR data, market tracking system, economic data, emission inventory, air monitoring data, and forest protocol annual report information) and develop the appropriate tools to determine if there are impacts due to compliance with the cap-and-trade regulation as information becomes available. We will work with other State agencies and local air districts during this process. The adaptive management strategy will go through a public process to allow stakeholders to provide comments.

We will monitor the implementation of the cap-and-trade regulation and will develop appropriate responses to rectify any identified adverse impacts. If it is determined that an adverse impact has been identified as result of the regulation, ARB will conduct a public process and develop recommendations for Board action.

We will update the Board at least annually on the status of the cap-and-trade program, including activities related to the Adaptive Management Plan in accordance with the direction in Board Resolution 10-42 and 11-32.

Delay Action

B-13. Comment: Ag Council appreciates ARB's decision to delay implementation of cap and trade for one year. There are many outstanding issues with this regulation that we continue to work on, therefore the delay in implementation is appreciated by our membership. (ACC5)

Response: We appreciate the support.

B-14. Comment: It is not clear to us that the Cap-and-Trade program is ready for implementation in 2012-2013. New developments such as the 10 percent cut in allowances and its impact on companies need broader evaluation. We ask that ARB consider deferral of the start of the program to resolve these and other uncertainties. (CONOCO3)

Response: This comment falls outside the scope of the second 15-day changes to the regulation. Nevertheless, we believe that we have sufficient time before the compliance obligation begins in 2013 to allow us to address outstanding issues and ensure that the market tracking system is developed and tested. We also note that the benchmark stringency referred to by the commenter as a "10 percent cut in allowances" is not a new development, but rather was specifically outlined in Appendix J of the Staff Report and in response to Board inquiry at the December 16, 2010, hearing.

Economic Harm/Burden

B-15. (multiple comments)
Comment: Valero believes that if ARB thoughtfully considers all comments, then the final regulation would minimize the impact to the economy, industry and consumers. (VALERO3)

Comment: It is imperative for the Board to "get this right." Not only does this regulation affect the entire California economy, but it has the potential to be the model for other regions and states. If additional regulatory proceedings are needed to get it right, then WIRA recommends that they be done as soon as possible. (WIRA4)

> **Response:** These comments fall outside the scope of the second 15-day changes to the regulation. No response is necessary. Nevertheless, we note that we will monitor the implementation of the regulation and propose regulatory changes, as necessary.

Cap/Allowance Budget

B-16. Comment: CCEEB is concerned that the cap in this regulation exceeds previously defined scoping plan levels, driving the program reductions below 1990 emissions levels. This is particularly evident given the new 2010 emissions levels that are roughly half of the projected emissions for 2012. CCEEB recommends that the ARB clearly articulate the rational for this increased compliance obligation and the reasons why the emission estimates are higher when the economy, production, and business are down, and reconcile this data with the updated GHG forecast and the recent Legislative Analyst Office analysis. (CCEEB4)

> **Response:** This comment falls outside the scope of the second 15-day changes to the regulation. Nevertheless, as stated in the responses to the 45-day and first 15-day comments to the regulation, the main difference between the estimated cap of 365 $MMTCO_2e$ in the Scoping Plan, and the 334 $MMTCO_2e$ cap in the regulation is the Scoping Plan estimate was based on entire sectors. It did not consider sources that are not addressed by the regulation or certain types of transportation fuels that are used in small quantities.
>
> We disagree with the commenter's assumption regarding projected emissions for 2012, and adjusted our estimates to take into account for the economic downturn. The changes in fuel use are reflected in the baseline levels. The initial 2012 allowance budget of 165 $MMTCO_2e$ per year was selected based on projected 2012 emission levels and by using mandatory reporting data to ensure accuracy in cap setting.

Sectors/Facilities: Oil and Gas

B-17. Comment: Methane accounts for much of the total GHG pollution from the oil and gas sector and it also has an extremely high global warming potential. According to the 1996 IPCC Second Assessment Report, methane was estimated to be 21 times more effective at trapping heat in the atmosphere when compared to CO_2 over a 100-year time period. However, the global warming potential of methane has been revised upward and in the IPCC Fourth Assessment Report in 2007, methane is now estimated to be 25 times more effective at trapping heat in the atmosphere when compared to CO_2 over a 100- year time period. We draw your attention as well to a review of methane waste issues undertaken by the Government Accountability Office (see Federal Oil and Gas Leases: Opportunities Exist to Capture Vented and Flared Natural Gas, Which Would Increase Royalty Payments and Reduce Greenhouse Gases (GAO 11-34, October 2010), as well a June 2011 letter (attached) to the U.S. Department of the Interior, U.S. Bureau of Land Management, U.S. Department of Energy, U.S. EPA, and Council of Environmental Quality from twenty-one environmental organizations, discussing methane waste from oil and gas development. Replacing high-bleed pneumatic controllers with available low-bleed controllers not only reduces methane emissions, but also improves operational efficiency. However, other voluntary incentive programs, such as U.S. EPA's Natural Gas STAR Program have failed to spur large-scale retrofits. Despite the potentially large GHG benefits from such conversions, the general trend has been that funds that might be directed toward efficiency retrofits have otherwise been directed toward other expenditures (such as expenditures to increase production that may have greater capacity to increase industry revenues). Given the high global warming potential of methane, and the strong and compelling public interest in minimizing GHG emissions impacts, TWS believes that direct regulations should be implemented to require these cost-effective, efficiency producing retrofits, especially where public lands have been made available to companies for oil and gas development. (TWS2)

> **Response:** No response is necessary. Please see responses in Chapter III regarding our evaluation of alternatives to the cap-and-trade regulation.
>
> In addition, we have announced that we are working on an offset protocol that would address high-bleed pneumatic valves used in oil and gas operations. In addition, ARB has the authority to pursue direct regulations in combination with the cap-and-trade regulation.

Refineries

B-18. Comment: Elements of ARB's planned program pick winners and losers within the State and create competitive disadvantages for in-state operations that will encourage the import of fuel from out-of-state and international refineries. (CONOCO3)

> **Response:** We disagree that the regulation creates competitive disadvantages at the sector level. We analyzed the potential for competitive disadvantages of a

cap-and-trade program on covered entities, and the regulation includes methods to reduce competitiveness loss through the allocation process. For example, free allowances are distributed to industrial sectors that are affected by carbon allowance costs and do not have the ability to pass through costs to customers without suffering a competitive disadvantage. We worked with the refinery sector to develop an allocation mechanism based largely on a method proposed by the industry. The industry understood that less-efficient facilities within the sector would receive fewer allowances than those that are more efficient. Board Resolution 11-32 directs the Executive Officer to continue to review information concerning the emissions intensity, trade exposure, and in-state competition of industries in California; and to recommend to the Board changes, if needed.

New Source Performance Standards (NSPS)

B-19. Comment: PacifiCorp understands that ARB has been working with the U.S. EPA to recognize the State's greenhouse Cap-and-Trade Program as equivalent to the EPA's proposed New Source Performance Standards (NSPS) for GHG emissions under the Clean Air Act pursuant to section 111(b) for new sources or section111(d) for existing sources. Specifically, PacifiCorp understands that ARB has requested reciprocity for sources located in California that will be subject to the EPA's new NSPS GHG rule since those sources will also be required to comply with the State's GHG cap-and-trade program. PacifiCorp is concerned that reciprocity for in-state sources may have a discriminatory impact on out-of-state sources that import electricity into California. Out-of-state sources importing power into California will potentially be subject to the new NSPS GHG rule in the state where the source physically resides. When another state in which PacifiCorp operates develops its implementation plan to satisfy its obligations required by the new NSPS GHG rule, California's reciprocity, if it does not exempt out-of-state sources from the state's Cap-and-Trade Program will create a situation where an out-of-state source is regulated twice under the new NSPS GHG rule —once in the state where it physically resides and again in California. This issue should be clarified. PacifiCorp specifically requests that ARB consider how reciprocity would affect out-of-state sources, and specifically consider how reciprocity for in-state sources may create a discriminatory impact on out-of-state sources, and whether changes to California's Cap-and-Trade Program would be necessary. Though as not currently imminent, a discriminatory impact on out-of-state sources may also occur if and when a federal or other state GHG cap is imposed. PacifiCorp recognizes that ARB is cognizant of this issue and respectfully requests that ARB continue to consider this in future changes to the Cap-and-Trade Program. (PACIFICOR4)

Response: ARB has been involved with U.S. EPA and stakeholders in early discussions regarding NSPS for GHG emissions (see http://www.epa.gov/airquality/ghgsettlement.html). However, no federal rule has been proposed, and the timetable for proposal is unclear. Therefore, currently the commenter's concern regarding reciprocity is premature and any ARB response here would be speculative. Board Resolution 11-32 directs us to report to Board at least annually on the status of the cap-and-trade program, including federal greenhouse gas activities, which include federal equivalency for a state program. As requested, we will continue to consider this issue during the cap-and-trade program implementation and consider changes, if warranted, to the cap-and-trade program.

Linkage

B-20. (multiple comments)
Comment: Chevron understands, based on conversations with ARB staff, that while this 15-day package represents the completion of the December 16 rulemaking, several important issues will be considered next year. Without linkage and an adequate supply of offsets, the program will not be able to function in an economically efficient manner. Trade exposure to out-of-state competitors creates competitive disadvantage for California's refining and production sectors and threatens California's economic well-being and energy balance. (CHEVRON4)

Comment: In its December 15, 2010 comments to ARB, BCSE emphasized that the California cap-and-trade program should be compatible with other state and regional programs, both to lay the groundwork for a national program and to allow for possible linkages with other carbon markets. The Council continues to encourage ARB to work with other programs to develop linkage agreements. (BCFSE2)

Comment: ConocoPhillips supports the development of federal climate change policy in the United States that is economically efficient and environmentally effective, but that ensures the availability of secure, affordable, and reliable energy. We believe that a mandatory national framework with international linkages will be the most effective approach to achieve meaningful impact on global greenhouse gas emissions. As such, we oppose development of a patchwork of state-level policies. (CONOCO3)

Response: These comments fall outside the scope of the second 15-day changes to the regulation. Nevertheless, we recognize the importance of linkage with other jurisdictions and the need for an adequate supply of offsets. We analyzed the potential of a cap-and-trade program on California businesses, and the regulation includes methods to reduce competitiveness loss through the allocation process.

The proposed regulation establishes a framework for linkages and considers the issue of linkage with other GHG emissions trading systems. Subarticle 12 of the regulation includes procedures to evaluate external GHG emissions trading system. Establishing linkage with other programs will require further assessment and establishment of a formal rulemaking process under the APA before allowances and/or offset credits from an external program can be used for compliance with this regulation. When evaluating whether we should link to another program, we will consider criteria that the potential linked program must meet, to ensure that the linked program has provisions for cost-containment, market tracking, registration, monitoring, reporting, verification, and enforcement that are reliable and sufficient to ensure its environmental integrity. California is a partner state of WCI and has been actively involved in WCI activity and the design element. We will evaluate linkage with WCI partner jurisdictions that may be ready to implement their cap-and-trade programs in the near term.

Duplicative Regulations

B-21. Comment: CCEEB is concerned that California businesses will be subject to duplicative GHG regulations from the State and federal government. Although it is unlikely that a federal cap-and-trade regulation will be forthcoming in the near term, U.S. EPA has been working to develop GHG regulations such as GHG BACT and NSPS. Compliance with duplicative regulations will be costly and will not result in material benefit toward our GHG reduction goals. CCEEB recommends that ARB clearly state its intent to not subject California's businesses to duplicative GHG regulations. (CCEEB4)

Response: This comment falls outside the scope of the second 15-day changes to the regulation. Nevertheless, we recognize the importance of harmonization between State and federal GHG emissions-reduction requirements. In Board Resolution 10-42, the Board directed the Executive Officer to work with U.S. EPA on the development of a federal regulatory framework to grant delegation or equivalency to California’s climate change program where appropriate. In addition, Board Resolution 11-32 directs us to report to Board at least annually on the status of the cap-and-trade program, including federal greenhouse gas activities, which include federal equivalency for a state program. We are working with U.S. EPA on how the Clean Air Act (CAA) would benefit from GHG emission-reduction efforts. Further emissions accounting will be needed once U.S. EPA has finalized their requirement and accounting approach.

C. ALLOCATION OF ALLOWANCES

Support for Auction

C-1. Comment: The preferred option for allocating allowances in the cap and trade program would be to allocate allowances exclusively with auctioning and address leakage issues via border adjustment if and when they arise. UCS urges CARB to maximize the use of auctioning in the cap-and-trade program in order to achieve the greatest public benefit from the program. Most of our comments and concerns could be adequately addressed by simply instituting auctions rather than the current free distribution of allowances for the industrial sector. (UCS8)

> **Response:** This comment falls outside the scope of the second 15-day changes to the regulation. We addressed comments on border adjustments, as well as comments on auctioning as an allowance distribution method, in responses contained in Chapter III and Chapter IV.

Multi-Year Allocation

C-2. (multiple comments)
Comment: CARB's proposal to issue allowances on a one year forward only basis creates uncertainty for entities in terms of financial and capital planning purposes. (CALCHAMBER4)

Comment: Without the benefit of multi-year allowance allocations, regulated entities will not be able to properly determine their growth potential and plan accordingly to select new sites or expand current facilities. A multi-year allocation approach allows regulated entities the time necessary for capital planning purposes. It is not very feasible for a facility to responsibly plan an expansion or retrofit that will take multiple years, if it must start the project without knowing how it will obtain allowances to cover facility emissions in future years of the project. Multi-year allocations will allow businesses to plan ahead. (CALFP4)

> **Response:** These comments fall outside the scope of the second 15-day changes to the regulation. However, we do not believe multi-year allocations are necessary. We believe that there is enough information in the regulation for a firm to forecast an expected allowance allocation through 2020. Because allocation is tied to production, if the firm can anticipate future levels of production they can calculate their allowance allocation for that period.

Facility Shutdown

C-3. Comment: Section 95891 of the regulations indicate that facilities may not retain (nor gain) allowances if they cease operations. Depriving sources with the ability to gain revenue from the shutdown of emitting units will:

- Increase compliance costs. When streams of allowances from shutdown facilities are repatriated back to the state we can presume that they will be sold through a state sponsored auction with a minimum clearing price ($10 in 2012) that will likely be above that which is offered on the secondary market.
- Encourage older/inefficient emitting units to stay on line. Knowing that it will forfeit its allowances and credits a source operator will be inclined to keep the source operating as long as feasible. This will have the dual effect of discouraging equipment replacement (thereby keeping inefficient sources online) and keeping credits from the market (thereby reducing supply).

As a means to mitigate costs and encourage companies to remove older and inefficient sources, CARB should allow for the creation of shutdown-derived offsets. Further, should CARB elect to issue multi-year allowance streams, companies should be allowed to retain, redeploy, or sell allowances that are no longer needed by sources that are curtailed or shutdown. (BGCEBS)

> **Response:** We do not agree that the regulation promotes the use of inefficient units. Our industrial allocation approach is based on emissions efficiency benchmarks. Product-based benchmarking is based on emissions intensity per unit product. An inefficient unit relative to these benchmarks will be disadvantaged relative to a more efficient unit. The amount of allowances received is proportional to the amount of product produced, so a facility that runs at a low level will not obtain the same level as it would at a higher level of operation.
>
> We will not provide shutdown-derived offsets because an offset has to result from an activity that is not required by regulation or would otherwise occur in the absence of receiving offset credits. "Offsets" generated by a facility shutdown would not meet the criteria for "additionality" under AB 32.

Positive Verification Requirement

C-4. Comment: WSPA supports the use of a well-designed benchmarking method that results in an equitable distribution of allocations for facilities in the upstream oil and gas extraction sector as well as the downstream refining sector. Characteristics of a well-designed benchmark (i.e., one that yields equitable treatment of facilities and does not produce arbitrary windfalls or shortfalls) include: an accurate and reliable reflection of a facility's GHG emissions considering the quantity of oil and gas produced, or the processing required; inclusion of GHG emissions associated with use of electricity irrespective of generation location (i.e., on-site or off-site); inclusion of GHG emissions associated with hydrogen production irrespective of location (i.e., on-site or off-site); clarity and transparency in the calculation methodology; fulfillment of ARB's objective of minimizing leakage and providing assistance during a transition period, and specific to the upstream sector, segmentation of comparable facilities based on appropriate consideration of key operational parameters. Section 95890 requires that an entity obtain a positive or qualified positive verification statement to be eligible for direct allocation. WSPA believes that this section needs to recognize that there are circumstances where an entity cannot get a qualified positive product data verification—this is a new procedure that could have complications. WSPA recommends that the regulation be amended to allow an EO decision or a method for direct allocation in case a decision is pending on a qualified positive verification or in case of an adverse verification opinion. WSPA further recommends that the regulation be amended to allow an EO determination for a direct allocation in case a decision is pending on a qualified positive verification or in case of an adverse verification opinion. (WSPA4)

> **Response:** We do not believe there is a need to modify the regulation and allow an EO decision or to create a method to allow entities that did not obtain a positive or qualified position product data verification direct allowance allocations. Appropriate flexibility is already included in the verification process.

Product Benchmarks

True-up

C-5. Comment: On September 8, 2011, CSCME submitted brief comments to CARB proposing a modification to the "true-up" method in the allowance allocation system. This simple modification would ensure that facilities receive the appropriate true-up for the last two years of the program if the Cap-and-Trade program is discontinued. CSCME now reiterates those comments, and attaches them to ensure they are part of the record of this proceeding. (CSCME5)

> **Response:** We believe our second 15-day changes to the regulation for the "true-up" method is sufficient. We prefer to keep the calculation of allowance allocation separate from the calculation of compliance obligation. We will address the issue of discontinuation of the program, if and when the need arises, through future rulemaking.

Stringency: Support or Request Increased Stringency

C-6. Comment: UCS urges the promotion of technology-forcing best practices by basing benchmarks on best-in-class international or national carbon intensity standards which are transparent, based on publicly available information and do not subsidize dirtier lower quality crude feedstocks. (UCS8)

> **Response:** We believe that benchmark stringency should reflect the emissions intensity of highly efficient, low-emitting facilities within each sector. We do not agree that our approach subsidizes lower-quality crude feedstocks. We believe that complexity-adjusted allocation methods are neutral to crude quality. That is, they neither excessively penalize nor reward refineries sourcing poorer quality crude. We do not believe these methods create an incentive to switch to poorer quality crudes. The phase-out of free allocation and the switch to auctioning as the primary method for allocation to the refining sector by the third compliance

period will penalize facilities with more emissions-intensive processing, including more emissions-intensive processing due to crude quality.

Stringency: Request for Reduced Stringency

C-7. Comment: Appropriate and equitable benchmark methodology is important as it serves the fundamental basis for the distribution of free allowances. CARB should not use benchmarking methodology to serve unrelated goals and thus undercut the basic principle of free allocation of allowances to prevent leakage of emissions and economic activity of energy intensive trade exposed industries. (CALCHAMBER4)

Response: We disagree that we are using the benchmark methodology to "serve unrelated goals." We believe our benchmark stringency will reward efficient facilities that have taken early actions to reduce their greenhouse gas emissions, as required by AB 32.

C-8. (multiple comments)
Comment: Protecting against leakage of emissions and jobs must continue to be the paramount cap-and-trade design issue for CARB. With none of California's neighboring states committing to climate targets and policies, emissions leakage will continue to be a risk for the program and a risk for California businesses. Unlike their out-of-state competitors, California's industries will face carbon costs that will make them less competitive. While CARB appears to recognize the need to protect California's carbon intensive trade exposed industries by proposing direct allowance distribution to these industries, the proposed arbitrary 10 percent "haircut" is completely inconsistent with the need to protect these industries and California jobs. CARB should not arbitrarily withhold up to 10 percent of the allowances that trade exposed and energy intensive industries need in order to minimize costs and leakage. Yet, CARB continues to propose an arbitrary 10 percent reduction in the number of allowances to be distributed to leakage prone industries. This is inequitable, does not minimize costs, and does not minimize leakage. It is not necessary or even helpful in ensuring the stringency of the overall cap. CARB should discontinue this proposal, and should not arbitrarily withhold allowances that it has already determined these industries need. (AB32IG3)

Comment: Rather than developing a "soft start" to the Cap and Trade program as previously approved by CARB, the 10 percent reduction (termed 10 percent haircut) poses potential problems for the availability of allowances at the onset of the program when uncertainty is expected to be greatest. At the very least, this will lead to severe inefficiency of the Cap and Trade Market, and likely will increase the already significant cost burdens to all industry sectors. No documentation or information substantiating the need for the haircut has been presented. In reality, the reductions originally planned during the first compliance period now occur up front instead of staggered over a three to five year period. Also, the reduction in allowances has no relevant air quality benefit or emission reductions. It basically will generate hundreds of millions of dollars for no stated purpose and is a hidden tax on industry. (CIPA2)

Comment: In the proposed regulation, the benchmark is set at a level of 90 percent of industry average for the refining sector and most other industries. Setting the benchmark at this level will create an immediate shortage of free allowances, introducing this level of stringency at the outset of the program will create immediate harsh impacts, dilute the impact of the assistance factor, and be redundant with the cap reduction factor. The only clearly stated need for allowance withholdings during the first compliance period are one percent for the price containment reserve and 0.5 percent for renewable electricity emission reductions. We do not believe there is any justifiable reduction in free allowances beyond 1.5 percent in the first compliance period. Because the cap reduction factor already provides for a two percent year reduction in free allowances, we maintain that the 90 percent initial reduction is overreaching, beyond the needs of the program, and will cause unintended consequences like leakage. (TESORO3)

Comment: The current cap-and-trade proposal continues to arbitrarily set the benchmark for industry sectors at 90 percent of the industry average, which would require regulated entities to purchase ten percent of their allowances at the start of the program. CARB's proposal to withhold ten percent of emission allowances (the 'haircut') is an unjustified tax on business that will lead to leakage of production and jobs while failing to reduce GHG emissions required under AB 32. The ten percent haircut puts California companies at an immediate competitive disadvantage and runs contrary to CARB's recognition of a 'soft start' transition intended to mitigate economic and emissions leakage. So long as California continues to move forward by itself in a cap-and-trade program, the risk of economic leakage remains high; CARB must take every step to avoid this scenario. The best way to avoid these impacts and to mitigate risk to energy intensive trade exposed industries is through the free allocation of allowance. 100 percent allowance will provide the necessary transition to a lower-carbon economy, and allows businesses to stay competitive and keep investments in the State. (CALCHAMBER4)

Comment: ARB should provide 100 percent free allowances to industry to prevent leakage of jobs and emissions out of the state, consistent with the December 16, 2010, cap and trade rule. One way the agency can provide a soft start to benchmarking and still achieve its objectives is to set the benchmarks at 98 percent of the industry average in the first compliance period, followed by 93 percent in the second period and 90 percent in the last compliance period. This will allow transition time for reductions to be made and for offset supply to be developed. (CHEVRON4)

Comment: ARB's modified cap-and-trade draft regulations allocate significant levels of permits to covered entities in the early years of the program, moving to an auction of greater volumes of allowances over time. In a more recent development, the draft regulation now includes significant additional reductions in allocation to industrial entities, through the benchmarking design approach, starting on day one of the program. This recently enacted 10 percent " haircut" significantly increases the compliance obligation for the industrial sector early in the program—and runs counter to the very carefully thought-out and justified "soft start" to the program. At this rate, industry will find it very difficult to adjust to the increased costs of auction, threatening competitiveness, and jobs, and impacting consumer energy prices, and potentially affecting public support for the program. Simply put, allocating allowances helps to minimize leakage and prevent California industries from being put at a competitive disadvantage. It is important to keep in mind that for companies who have been designated as trade exposed, free allocation of allowances is a way to mitigate their exposure and to lessen the impact of a transition to a low carbon economy. With input from the Governor's office, ARB has concluded that free allocation of allowances, especially early in the program, is necessary and warranted, and has as a result provided for a transition period. Therefore, when considering a method to distribute these free allowances, it is important that the method chosen and the design elements of that method do not run counter to the intentions of freely allocating allowances. Of most concern in this regard is the intention to reduce initial allocation by 10 percent (either through the benchmarking process or in other ways), which is suggested by staff to be necessary in order to fund various accounts or programs. This is a significant reduction in allocations and it would increase compliance obligations for affected regulated parties by 250 percent (from four percent to 14 percent) in the first compliance period—this increase being in a period that had been designed as providing a "soft start" and transition period for regulated entities. The justification for, and design of, a "soft start" to the cap and trade program was very carefully considered in the earliest scoping discussions for Cap-and-Trade. The need for a soft start was clearly articulated by then Governor Schwarzenegger and subsequently affirmed by ARB Leadership and their Board. The upshot was a policy of full allocation in the first compliance period to sectors determined to be trade exposed. To the contrary, the current rules do not square with that determination, so it is very inconsistent for there to be such a significant reduction in first compliance period allocation with the resulting 250 percent increase in the compliance obligation at the outset of the program, as highlighted above. Significant time and capital investment are needed to meet long-term emissions reductions goals and transition California to a lower-carbon economy. IETA recommends this ten percent haircut be removed, and that the regulation adheres to the concept of a soft start. This will better help participants acclimate to the market and permit time for large capital investments to yield emissions reductions, keeping costs down, reducing trade exposure, and improving efficiency. We strongly urge ARB to rescind any consideration of a reduced allowance allocation (or "haircut" as it has been referred to). The use of the first compliance period should continue to be viewed as a period that while it will deliver real, tangible emission reductions, allows regulated parties to transition to a low carbon economy. (IETA4)

Comment: The proposed initial 10 percent reduction and set-aside of allowances is unexpected and unnecessary. A graduated start of the program, as presented in the Scoping Plan, would give California consumers and businesses time to adjust to the cost impacts of this regulation. This is particularly relevant given the now truncated first Compliance Period of the program which is now two instead of three years. ConocoPhillips opposed this 10 percent cut in our August comments when it first appeared in proposed public rulemaking and has met with staff to communicate our competitive concerns. Our position is supported as follows:

- Not a Slow Start: This is not the “slow start” that was discussed for the start of the program.
- Change not anticipated: ConocoPhillips, and in our opinion the refining sector in general, did not anticipate this proposed late change in the regulation. To the best of our knowledge, it was only made clear for the refining sector in the July 25 public release.
- Not aligned with prior ARB/WSPA discussion: During the cooperative workgroup meetings on refining benchmarking earlier this year, the documents and examples on allocations discussed with ARB staff clearly assumed only a four percent or less (3.7 percent) cut in allowances due to the cap reduction during the first Compliance Period. Discussions did not include the 10 percent cut plus the 3.7 percent cap reduction now proposed by ARB. This 13.7 percent total initial cut is not a slow start.
- Step Change in Costs: This significant loss in allowances to ConocoPhillips and the accompanying high costs would hit on January 1, 2013, only 14 months from now. Based on current refining sector benchmarking these costs could range from $5 to $10 million per year based on ARB’s minimum 2013 carbon market price of $10 per tonne (because this is the minimum price, the actual costs are expected to be much greater). These costs have not been assumed in our business planning and allocation of funds. Actual costs may be higher with higher carbon market prices.
- Importing Refineries not Subject to this Cap-and-Trade Cost: No refinery outside of California is subject to this requirement to buy allowances or offsets for refinery emissions. This creates a competitive disadvantage for California refineries that will be quickly exploited by foreign and out-of-state refineries.
- Immediate Trade Exposure: ARB recognizes the refining sector as heavily trade-exposed in the first compliance period by granting the sector a 100 percent “Industry Assistance Factor” in the Regulation’s section 95870. The newly proposed 10 percent cut is inconsistent with this recognition and degrades the protection ARB previously realized was necessary for our heavily trade-exposed industry. As a result of the 10 percent cut, trade exposure, which is already present, would increase on January 1, 2013. ARB has acknowledged potential leakage in industry operations in earlier rulemaking documents and that it can actually increase global emissions.
- Refinery Viability and Jobs Impact: Any additional trade exposure puts our refineries at a disadvantage, impacting viability, and potentially putting high-paying manufacturing jobs at risk. Further, a refiner will be less inclined to invest in the sites and that could put construction and other trade union work in jeopardy.
- Heavy Overlay of Programs: The 10 percent cut in allowances poses yet another overlay of AB 32 programs on the refining industry. This overlay includes at least five regulations that include the Low Carbon Fuel Standard for gasoline and diesel fuels, penalties for high carbon-intensity crude oils, Cap-and-Trade for refinery emissions in 2013, Cap-and-Trade for consumer product emissions in 2015, and the AB32 Implementation Fee regulation. This year alone we will pay $3.7 MM in fees to ARB for AB 32 regulation and program development. The

imposition of Cap-and-Trade for product emissions in 2015 is problematic and we look forward to discussing this with ARB in future Cap-and-Trade rulemaking improvements.

- Revenue Take for Unclear Uses: It is not clear how the revenues from the 10 percent cut in allowances will be used. ARB does state that the proceeds from the sale of these allowances will be deposited into the Air Pollution Control Fund and will be available for appropriation by the Legislature for the purpose designated in California Health and Safety Code sections 38500 et seq. The uses of this significant additional revenue from the 10 percent cut should be made more transparent. Only 1.5 percent of the total is clear for use in the Allowance Price Containment Reserve and Voluntary Renewable Electricity Reserve Account. ARB has stated publicly that the AB 32 program should raise approximately $500 million in revenue from the sale of allowances in 2013. (CONOCO3)

Comment: The United Steel Workers (USW) and our members are opposed to a Cap and Trade scenario for refining that does not recognize full trade exposure when granting allowances to trade exposed refining. Full trade exposure means 100 percent granting of allowances for all refineries in initial years, while companies have time to permit and build out their projects. These projects will enable refineries to secure high paying jobs while at the same time moving toward greener production methods. Since the passage of AB 32 in 2006, refineries have not had adequate time to make step changes in energy efficiency. Compliance will materialize as in-state investment in energy efficiency projects. Statewide energy improvements will not happen if leakage is at the center point of the program. The reduction in the cap on greenhouse gases will drive carbon prices up, you don't need a big cash call in the first year of the program to meet the goals of AB 32. The 10 percent reduction of free allowances for some facilities is a tragic invitation for refiners to leave the State or increase imports therefore jeopardizing jobs. As Cap and Trade revisions are proposed, eight facilities are required to pay fees reaching $20 million per facility creating an unlevel playing field starting day one of this regulation. A slow and steady start of the program, as initially envisioned to allow time for investment and permitting, will preserve California jobs and minimize imports of intermediates and finished products. Policies favoring imports from other states or countries that have done little or nothing to regulate greenhouse gas emissions hurts our members and does not help the overall environment as it relates to greenhouse gases. Don't invite a flood of new imported product into California that will compete at reduced costs and will place our members out of work. CARB must protect California refineries from imports that will result from a poorly designed in-state Cap and Trade Program. If CARB fails, the result will be a severe loss of California jobs and failure to reach our collective goal of greenhouse gas emission reduction. USW requests that CARB more carefully protect against trade exposure. Petroleum refineries will comply with reductions through energy efficiency investments. This can only happen if there is a level playing field with in-state refining because imports currently do not, and should not be invited to play a role in California's manufacturing sector. CARB must not pick and choose winners and losers in the first year of the program because no company has had time to prepare for reductions. We ask CARB for three important deliverables:

- Eliminate the 10 percent allowance take away from certain California refineries in the early years;
- Revise classification and timelines for the downstream refining sector, from medium trade exposure to high trade exposure. Such action is consistent with upstream exploration and production currently classified as high trade exposure; and
- Close the import loophole and associated leakage by providing a slow start and level playing field for California refineries in the Cap and Trade Program. Protect in-state refineries from unfair competition from refineries in other states and nations outside CARB's enforcement jurisdiction. (USW)

Comment: WSPA is very concerned, and joins others in opposing, ARB's imposition of a 10 percent reduction in allowances at the start of the cap and trade program. Rather than encouraging a "soft start" to the program and improve the chances of the program's success, the 10 percent reduction works to frustrate that effort by increasing costs and uncertainties to participants at a time when the economy cannot support additional costs. The reduction also poses a unique, additional hurdle for trade-exposed industries such as the oil and gas production and refining industries by imposing costs to operations in California that are not imposed on those operating outside the State. In fact, the proposed reduction in free allowances is a policy decision that is in direct conflict with ARB's recognition, and stated intent, to mitigate the impacts of the C/T program on trade-exposed industries. Again, this is so because the proposed reduction exacerbates the impact of trade exposure to facilities within California because it imposes immediate and obvious costs to California operators that are not imposed on those operations outside the State. Because importers are not affected by allowance costs, this inequity can lead to leakage of goods and/or services to operators outside the State—again an outcome that ARB indicated it wished to avoid. Finally, the immediate reduction in free allowances, in reality, simply represents an abrupt transfer of millions if not billions of dollars of revenue whose justification and ultimate use is both undefined and undocumented. While, we have been told that the 10 percent reduction is to provide incentive to be more GHG efficient, it seems obvious that the cap and trade program itself provides the necessary incentives. This additional 10 percent "incentive" is an unnecessary "add-on" that may cause a sudden unnecessary disruption that could negate a soft start to this program. The reduction has no impact to air quality nor will it contribute to emission reductions. Rather, it will generate literally hundreds of millions of dollars from participants for undefined and unidentified uses. In fact, up to this time, ARB has simply not been transparent in developing the requirements of the 10 percent reduction nor has the agency fulfilled the requirements to clearly document the need for that element within the Cap and Trade Program. ARB should remove the 10 percent reduction in allocations from its program. Should it wish to pursue it in the future, the Agency should document: 1) the need for this element; 2) the anticipated environmental benefit; and 3) that the supply of allowances and offsets will be sufficient to ensure companies can comply with AB 32 limits. (WSPA4)

Response: We do not agree. We believe that benchmark stringency should reflect the emissions intensity of highly efficient, low-emitting facilities within each sector. Our approach to allowance allocation will minimize leakage by incentivizing continued production and improved emissions efficiency from all facilities in California.

We strongly disagree with the comments that characterize the approach to benchmark stringency as unexpected. The use of "90 percent of average" stringency for product-based emissions efficiency benchmark was initially indicated in the Staff Report released in October 2010. The following is a quote from page J-35 of that document:

"Staff believes benchmark stringency should reflect the emissions intensity of highly efficient, low-emitting facilities within each sector. Our current thinking is that the targeted level of stringency would be created by evaluating each industrial sector's emissions intensity during a historical base period and targeting the benchmark to allocate 90 percent of this level per unit product."

The benchmark stringency was explicitly discussed at the December 16, 2010, Board hearing, at which the Board directed staff to develop benchmarks based on the overall approach outlined in the Staff Report and to determine whether a benchmark stringency of 90 percent of average is appropriate for all sectors. In the subsequent work of evaluating the benchmark values, we found that the stringency approach proposed in the Staff Report worked for many sectors but, in some cases, would set the benchmark at a level that was more stringent than the current emissions intensity of any existing Californian facility. For the sectors for which this occurred, we selected a benchmark based on the "best-in-class" value (i.e., the emissions intensity of the most GHG-efficient California facility). This change in approach was indicated on page 3 of Appendix B of the first 15-day notice entitled *Development of Product Benchmarks for Allowance Allocation*.

We developed this approach to benchmark stringency after careful analysis of California emissions intensity data and approaches used in other successful cap-and-trade programs. In selecting benchmark stringency, we are balancing the need to provide adequate transition assistance and minimize leakage with the necessity to meet AB 32's emission-reduction goals and prevent windfall profits through excessive free allocation.

Within each sector, facilities with efficiencies better than the benchmark, will be receiving more allowances than they will need, and can sell their excess allowances. Less efficient facilities will need to purchase allowances to fulfill their compliance obligations. Beyond the initial allocation period, the level of free allowances will decline through the use of a cap-declining factor and an assistance factor. Because allowances can be traded, the program provides incentives for those with the most cost-effective reduction opportunities to reduce emissions quickly.

Treatment of Energy Flows

C-9. Comment: There is a lack of transparency in development of the product-based emissions efficiency benchmarks. Table 9-1 of the regulation lists product-based emissions efficiency benchmarks for numerous activities. The development of individual benchmarks has not been a transparent public process due to the use of commercially sensitive data provided by the affected industries. The CCC appreciates the need for confidentiality, but is concerned that the lack of transparency prohibits validation of the data used to develop these benchmarks. For example, it is impossible to determine if all, some, or none of the benchmarks include steam imported from an off-site CHP unit as an input to the benchmark. In the 2nd 15-day modified regulation, the energy-based allocation calculation methodology in section 95891(c) was modified to clarify that the CHP exclusion in the “steam consumed” term applies only to steam produced from CHP units on-site. Allocations for on-site CHP are captured in the FConsumed terms, and steam imported from an off-site CHP unit is included in the SConsumed term. It is not clear if these same principles apply to the product-based emissions efficiency benchmarks calculation methodology. Since the off-site CHP unit is not involved in the benchmark development, there is no opportunity for the off-site CHP owner to validate the data that may or may not be used in the calculation and are being attributed to that CHP unit. While the “electricity sold” term appears to include all power exported or sold from a facility, it is not clear if electricity sold not to a utility, but rather to a host pursuant to Public Utilities Code Section 218(b), is included in the product-based benchmark for any particular industrial activity. CCC recommends that ARB explicitly state how CHP outputs produced both onsite and offsite are treated in terms of each type of benchmark. Such transparency is particularly important if the outputs are treated differently for different activities. If the thermal or electricity produced offsite by a third party is included in the benchmark calculation, the third party CHP owner should be given the opportunity to validate the data being attributed to their facility. This is important from the perspective of negotiating third party agreements to include cost recovery of the GHG emissions associated with the energy sold to the thermal/electricity host. (CACC3)

Response: We recognize the importance of properly considering indirect carbon costs in developing benchmarks for free allocation. In both the Staff Report and Appendix B to the first 15-day changes to the regulation, we clearly describe how energy flows and associated indirect costs impact benchmark values. Heat and power exported from a facility reduce the benchmark value because the operators of these facilities will be able to recover some of their carbon costs through the price of energy sold. Conversely, heat purchased will incur an additional indirect carbon cost for that facility, and thus emissions intensity values used in development of product benchmarks were increased to account for heat that was purchased.

An adjustment was not made for power purchased in establishing the benchmarks. This is because purchased power may not create an indirect carbon cost in all California utility service territories. It is ARB's goal to see a carbon price properly embedded in all utility rates. We will revisit this issue once the California Public Utilities Commission Proceeding addressing utility costs and revenue issues associated with greenhouse gas emissions (R.11-03-012) concludes.

With respect to concerns about the transparency of energy flows at individual facilities, energy purchases and sales information for each facility are collected in a confidential fashion as part of our program for the mandatory reporting of greenhouse gases. We cannot share energy flow data submitted by one entity with another entity even if the second entity is the counterparty in the energy transaction.

Cap Adjustment Factor

C-10. Comment: Design the program elements to ensure a smooth transition. CCEEB believes that because it is unlikely that California's program will be broadly linked with other State, federal or international programs in the early years, the combined effects of the cap slope and the allowance reserve deductions in the first and second compliance periods are likely to result in serious impacts to the economy. In the Functional Equivalency Document for the Cap-and-Trade, ARB reported 2010 emissions, which are far below projections made to justify the capped reductions. Since there are no linkages and there is a reduced need for emission reductions, CCEEB recommends that the cap slope be revised to reflect a smoother transition of one percent in 2013 and 2014, and two percent per year in the second compliance period and that benchmarking design elements that further reduce allocation to trade exposed industry early in the program be re-thought. This creates a smoother transition and realistically addresses the potential that California's cap-and-trade program will operate without the possibility of broad linkage to other State or federal programs in the first five years. (CCEEB4)

Response: We disagree. We believe the current allocation approach, including cap-decline factors, appropriately minimizes leakage. As stated in the responses to the 45-day and first 15-day comments to the regulation, the main difference between the estimated cap of 365 $MMTCO_2e$ in the Scoping Plan and the 334 $MMTCO_2e$ cap in the regulation is that the Scoping Plan estimate was based on entire sectors. It did not consider sources that are not addressed by the regulation or certain types of transportation fuels that are used in small quantities.

We disagree with the commenter's assumption regarding projected emissions for 2012, and adjusted our estimates to take into account for the economic downturn. The changes in fuel use are reflected in the baseline levels. The initial 2012 allowance budget of 165 $MMTCO_2e$ per year was selected based on projected 2012 emission levels and by using mandatory reporting data to ensure accuracy in cap setting.

C-11. (multiple comments)
Comment: We remain concerned over the greatly reduced cap adjustment factors for cement manufacturing. The latest version of Table 9-2 in the regulation adds two other sectors to this special category achieving just 7.5 percent carbon reductions in 2020 versus a 15 percent carbon reduction expected from all other sectors. The rational that these three sectors (Nitrogenous fertilizer manufacturing, cement manufacturing and lime manufacturing) have a high level of carbon emissions inherent to their process is not a sufficient explanation for an excessively weak cap reduction factor. These sectors could employ cleaner fuels, efficiency measures and greater use of alternatives to make significant carbon reductions. Special treatment for these three sectors is unwarranted and increases the compliance costs for other sectors. We recommend maintaining the same cap adjustment factors for all direct allocations. (KUSTIN18)

Comment: We propose that Table 9-2 be amended to recognize the following cap adjustment factor for glass manufacturing in recognition of the fact that approximately 25 percent of our GHG emissions are process-related. See attached chart for proposed amendment to Table 9-2. (SMITHS2)

Comment: GPI requests that CARB allow container glass to use the same Cap Adjustment Factor as has been provided to the cement manufacturing sector to account for the limited opportunity to control this portion of our emissions. (GLASSPI)

Comment: CARB staff has provided no justification for the selection of a 50 percent cutoff for eligibility for the lower cap adjustment factor. Thirty percent of “process emissions for which no cost-effective abatement opportunities are currently available” seems to PPG also to be “a significant level.” Flat glass manufacturers such as PPG will have only 70 percent of total CO_2E emissions available for potential reductions, while other industries subject to the same cap adjustment factor will have most or all of their CO_2E emissions available. PPG urges CARB to further revise Table 9-2 to include flat glass manufacturing as one of the sectors eligible for the lower cap adjustment factor. (PPGI2)

Comment: PPG’s comments on the proposed additional 15-day modifications to the regulation are focused on one issue: The need to include the flat glass industry in the group of industries eligible for the lower cap adjustment factor in Table 9-2. The flat glass industry is similarly situated to the three industries to which CARB has assigned the lower cap adjustment factor. A very significant proportion of CO_2E emissions from flat glass manufacturing – approximately 30 percent, based on PPG’s data result from the use of raw materials for which no substitute is available. (PPGI2)

Comment: Hydrogen production should be subject to the cap adjustment factors for sectors with process emissions greater than 50 percent. (IGPACC2)

Comment: Approximately 80 percent of carbon dioxide emissions from hydrogen production are process emissions. Hydrogen is produced using a chemical reaction in which a hydrocarbon feedstock reacts with steam to produce hydrogen, carbon dioxide and carbon monoxide. It is stoichiometrically impossible to reduce process emissions; they are determined by the chemical reaction used to produce hydrogen. Carbon dioxide emissions associated with energy production during the hydrogen production process are only about 20 percent of total hydrogen production emissions. CARB has determined that industries with more than 50 percent process emissions should be subject to lower cap adjustment factors than industries with less than 50 percent process emissions. CARB explained its rationale in the Notice accompanying the September 12 draft: In section 95891, Table 9-2 was modified to define "sectors and activities associated with process emissions greater than 50%", rather than "cement manufacturing". In the previous proposal, staff identified only cement manufacturing as an activity associated with significant level of process emissions for which no cost-effective abatement opportunities are currently available. However, stakeholders in other sectors whose activities also release process emissions raised a concern in comments. After careful consideration, staff determined that sectors with activities that are associated with process emissions greater than 50% are eligible for a lower cap adjustment factor taking into consideration the potential impact from the emissions that do not currently have cost-effective abatement opportunities. Because the process emissions from hydrogen production far exceed the 50 percent threshold that CARB has set, hydrogen production should be included in the group of industries subject to the lower cap adjustment factor. (ALLI2)

> **Response:** We believe a more gradual cap adjustment factor is appropriate for sectors where the majority of emissions are from process rather than combustion (greater than 50 percent of total emissions) and those that face a high leakage risk due to high emissions intensity. Except for carbon sequestration, a technology that is not yet fully developed, few options exist to reduce the process emissions in these sectors. We do not dispute that some cost-effective greenhouse gas abatement opportunities still exist at these facilities.
>
> Our decision to reduce the cap adjustment factor in Table 9-2 for three industries—nitric acid manufacturing, lime manufacturing, and cement manufacturing—was based on two criteria. The first was the magnitude of the process emissions as the majority of the total. The three industries where we provided a modified cap adjustment factor have process emissions in excess of fifty percent of total emissions. The second factor in our decision to reduce the cap adjustment factor for these three sectors was leakage risk and overall emission intensity. The three industries are all at a "high" leakage risk due to a "high" or "very high" level of emissions intensity. As we discussed in Appendix K to the Staff Report, high emissions intensity creates greater leakage potential since cap-and-trade compliance costs are relatively more significant for these sectors.

While flat and container glass manufacturing activities are at high risk of leakage, it is not due to high emissions intensity. For example, the emission intensity for the flat glass sector is less than twenty-five percent of the emission intensity of the least emission-intensive sector for which a reduced cap adjustment factor is provided. In addition, the process emissions from glass manufacturing are less than 50 percent of their total emissions.

The two hydrogen-production activities (gaseous hydrogen production and liquefied hydrogen production) are currently classified as at medium risk of leakage because the primary use of hydrogen is as an intermediate to production of transportation fuels by petroleum refineries. Petroleum refining faces a medium leakage risk. We are aware that the hydrogen producers would like a separate leakage risk evaluation of the non-refinery-based market for liquefied hydrogen. We will conduct such an evaluation and update the classification, if necessary, in a future rulemaking. This updated analysis may or may not make the production of liquefied hydrogen eligible for the reduced cap adjustment factor in future rulemakings.

In accordance with Board Resolutions 10-42 and 11-32, we will continue to monitor the emissions leakage risk for California production and recommend adjustments to allocation, as appropriate, to minimize this risk.

Price Containment Reserve

C-12. Comment: We would note the irony in CARB's intent to provide an allowance reserve (from which allowances will be sold at arbitrarily high prices) as a cost containment mechanism, and then propose to fund that reserve by withholding allowances that it should be directly allocating to leakage prone industries without charge. In this framework, the allowance reserve is not a cost-containment measure, but an arbitrary cost increase with no overall program benefit. (AB32IG3)

Response: We disagree and believe that the commenter has misinterpreted the design of the allowance price containment reserve. The allowances that are withheld to create the reserve are balanced against additional offset credits that are allowed to be used in the system. The design of the allowance reserve allows for an additional infusion of compliance instruments if allowance prices increase beyond initially anticipated levels.

Leakage: General

C-13. Comment: We are concerned that the analysis for trade exposure on a State level is an untested new process with potential for inadvertent oversight and errors and/or the cumulative impact of the other technology forcing complementary measures on California businesses may impact trade exposure in ways not fully accounted. To remedy this problem, CCEEB recommends that ARB establish a test to determine if an industry remains trade exposed. ARB's trade exposure test should rely on two criteria:

(1) is there a federal program; and (2) is there linkage to broad markets (i.e., larger or equal to the California market)? Allocations should be evaluated every three years in relation to the trade exposure test and other market indicators, such as the reports and recommendations by an independent market monitoring committee. (CCEEB4)

Response: Although we did not adopt the trade exposure test that the commenter suggests, we will continue to monitor leakage risk in the context of an evolving global and federal climate change policy framework.

C-14. Comment: It is disappointing CARB continues to propose less than 100 percent allowance allocation to the industrial sector in future compliance periods. The leakage analysis is insufficient to justify this. It is also premature to make this decision when there is time to do such analysis prior to the 2015 compliance time period. This decision should depend on the level of participation by other states and jurisdictions in the program as a key metric for how much each industry sector is at risk for leakage. (AB32IG3)

Response: We do not agree. We believe that our leakage analysis is sufficient to justify our approach to allowance allocation. We will continue to monitor leakage risk in the context of an evolving global and federal climate change policy framework.

C-15. Comment: Table 8-1 discusses the disposition of allowances for various industries that meet specific criteria under the Cap and Trade regulations. We understand that ARB is continuing to review where industries are placed on Table 8-1 as it relates to later compliance periods and we intend to further dialogue with ARB regarding the appropriate placement of our industry. (UNITEDAIRLINES3)

Response: We will continue to monitor leakage risk in the context of an evolving global climate change policy framework. We look forward to further dialogue with stakeholders on this issue.

C-16. Comment: CARB has reclassified the sectors, “all other petroleum and coal products manufacturing” and “tissue manufacturing” as high leakage risk and so these sectors now get many more free allowances in the second and third compliance periods. There is no supporting documentation or analysis to explain this change and its impacts. CARB should provide appropriate analysis prior to changing the categorization of these sectors to high leakage. (KUSTIN18, UCS8)

Response: We updated our leakage risk assessment for the “coke calcining” activity in the “all other petroleum and coal products manufacturing” based on new trade exposure information provided by the industry. There was no categorization for this sector or activity prior to the first 15-day changes to the regulation, and in the first 15-day changes to the regulation we were still gathering information to finalize our leakage risk assessment. We initially classified coke calcining as medium leakage risk based on our understanding that this sector and activity generally fell within the refining sector. However, through the dialogue with stakeholders, we found that calcined coke, which is a dry pure form of carbon, has different functionality and faces different market risk as compared to that of petroleum-derived fuels. Calcined coke is primarily used as anodes for aluminum smelting. Since there is no aluminum smelting in California, almost all calcined coke produced in California is exported.

We used the same methodology (evaluate emission intensity and trade intensity, then combine the two to determine leakage risk) that was applied to other industrial sectors as described in the Staff Report. Below are the values for coke calcining:

Emission intensity: We applied the same intensity as all other petroleum manufacturing products: 2,720 MTons CO_2 / $Million value added

Trade intensity: (import + export) / (domestic production + import) = (780,055 + 4,039,654)/(5,429,000 + 780,055) = 77.6%

Therefore, calcined coke is classified high leakage risk category because its emission intensity is medium and trade intensity is high.

We did not alter the classification of the “tissue manufacturing” activity within the “paper manufacturing” sector. We will continue to monitor leakage risk and adapt the program to new information through future rulemakings, as necessary.

C-17. Comment: To properly protect against leakage, it is imperative that CARB move forward in a way that does not have the unintended consequences of closing California manufacturing plants, eliminating thousands of California jobs, and reducing California’s income and property tax bases, while at the same time causing a shift / increase in GHG emissions because production has been moved to another jurisdiction (domestic or global) with less stringent requirements. (SMITHS2)

Response: This comment does not address a specific change in the second 15-day changes to the regulation. However, we agree, and designed the program to reduce leakage.

Food Manufacturing

C-18. Comment: Ag Council’s central issue of concern with the regulation still remains, and that is the designation of food manufacturing being categorized in the “medium” Leakage Risk Classification in Table 8-1. As stated in our previous comments, dated December 14, 2010, “the regulation states that the Industry Assistance Factor is essentially the ability an industry has to pass-on carbon costs. With low-cost competitors throughout the world, even a minimal increase in cost could displace certain market segments as demonstrated in the previously listed reports.” As stated in our comments submitted on August 10, 2011, “Ag Council believes the formula

for trade exposure and emissions leakage should be reevaluated to give special consideration to agricultural import and export markets. Food processing should be moved to the “high” leakage risk category, due to increasing international and domestic markets as stated in data points provided in our December comments. Additionally, food manufacturing is located in the second Industry Assistance Factor tier (Industry Assistance Factor of 100 percent; 75 percent; 50 percent), and should be moved to the top industry assistance factor tier due to price pressures from international markets. Even a minimal increase in costs could displace U.S. markets, giving more ground to domestic and international competitors. The EU’s ETS recognized the food processing industry as being especially vulnerable to leakage. While some food processing sectors were given 100 percent free allowances, others were considered under the de minimis category and therefore do not have to participate. California is no different, as many of our commodities compete for market space in a domestic and global economy. As such, by working within this regulatory system, we support moving food processors from the “medium” to the “high” leakage category in Table 8-1. Without our food processors, many sectors of production agriculture would not have a home in the marketplace.
Ag Council agrees with staff assessments in the December report, regarding domestic competition as being problematic as it relates to the food and agricultural industry. A different approach should be taken for food processing in determining compliance costs and/or emissions intensity. The emissions intensity variable in the product-based allocation calculation should be replaced with another variable that truly represents the cost of compliance for the food industry. Staff should take more time to work with the food processing industry to determine an appropriate factor for this variable.”
According to ARB staff, analysis has been conducted which demonstrates that the food processing industry will benefit from the cap and trade program during the first compliance period, therefore, food manufacturing remains in the “medium” leakage category. However, we have not been given the opportunity to review staff’s analysis of these findings, so our request to move to the “high” leakage category remains at the forefront. (ACC5)

> **Response:** We did not make changes to the leakage risk classification of the food processing sector at this time. However, we will continue to conduct additional analysis to further refine the leakage risk faced by the sector. As stated in Board Resolution 11-32, the Executive Officer is directed to initiate a study to analyze the ability of the agricultural industry, including food processors, to pass on regulatory costs to consumers. The Executive Officer will identify and propose regulatory amendments, as appropriate.

C-19. Comment: Food manufacturing is the only industry for which the CARB has aggregated up to the three-digit level per the North American Industry Classification System (NAICS). Every other industry is disaggregated at least to the four-digit level. Using three-digit level data obscures important differences among industry segments. For example, sector 3114 food processors are grouped with poultry processors in sector 3116, which have a very different energy use pattern. Food processors appear to be more energy intensive than the rest of the food manufacturing sector. Thus, the energy intensity measure for sector 3114 is diluted unless the NAICS code designations are expanded. CLFP recommends that the NAICS Code designation covering food processors be expanded. (CALFP4)

> **Response:** We agree and will work with the industry to conduct additional analysis at a greater level of disaggregation and make recommendations for changes in future rulemakings as appropriate. As stated in Board Resolution 11-32, the Executive Officer is directed to initiate a study to analyze the ability of the agricultural industry, including food processors, to pass on regulatory costs to consumers. The Executive Officer will identify and propose regulatory amendments, as appropriate.

C-20. Comment: Uncapped establishments will not be subject to any form of direct GHG regulation and thus will not incur any costs, either in implementing reductions or buying and selling allowances, or in regulatory compliance, associated with AB 32. This situation is identical to what was foreseen for implementing an EITE adjustment—regulated facilities are likely to face a competitive cost disadvantage to firms that provide a close substitute. The uncapped facilities, smaller emitters in this case, can increase their output and attendant GHG emissions, thus defeating the intent of AB 32 to reduce overall GHG emissions. Providing free allowances to large food processing emitters only partially mitigates this situation however. In an industry where so much of the competitive in-state production will fall below the regulatory threshold, and so few of the capped facilities have large emissions (only a half dozen of the sector 3114 plants emit more than 50,000 tons), better public policy is to uncap the entire food processing sector and leave the emission reduction strategies to other means. For food processors, almost all emissions come through either natural gas or electricity use. The load serving entities for both natural gas and electricity will be under the cap and trade program by 2015. The energy utilities will have strong incentives to encourage their customers, including food processors, to reduce their emissions through utility-based programs and measures. Thus, the food processing sectors will be regulated through an alternative means, but in a less costly manner. CARB should designate food processors (NAICS 3114) as an uncapped sector. (CALFP4)

> **Response:** We did not designate food processors as an uncapped sector. If we removed the sector from direct coverage they would no longer be eligible for free allocation, and free allocation is our primary tool to address leakage risk. We agree that coverage of natural gas providers in 2015 will provide greater equity between facilities that emit more than 25,000 metric tons of CO_2e per year and those below this threshold for direct inclusion. At that time, all emissions from natural gas combustion at a food processing facility will face a carbon price. As a result, we anticipate that smaller food processors (those emitting less than 25,000 metric tons of CO_2e per year) may wish to opt-in to direct coverage to become eligible for free allocation once natural gas providers are covered.

C-21. Comment: The purpose of distribution benchmarks is to establish equitable bases for distribution of free allowances within industries, taking into account the higher complexity and existing energy efficiency of California industrial facilities. CARB should continue to work with trade exposed and energy intensive industries to develop benchmarking methods that are supported by the impacted sectors. CARB should not be using benchmarking and other distribution methods to undercut the free allocation of allowances to energy intensive and trade exposed industries. CARB should not, for secondary reasons, adopt benchmarking methods which penalize the superior energy efficiency of California industries relative to competitors in other states, or methods which distort the distribution of allowances among industry members without regard to energy efficiency. To be fair to California industries, energy benchmarks should be set based upon a national standard. Setting industry-wide benchmarks, using only California facilities after nearly 30 plus years of energy efficiency efforts and expenditures by California industries, will only further exacerbate the trade exposure of California industrial facilities. Industry in California will be even more susceptible to competitors or startups in states choosing not to enact climate change regulations on their industrial base. Unfortunately, CARB's most recent proposals on benchmarking create increasing concern on the part of industry, that the basic principle of free allowance allocation is being subordinated to secondary concerns. This will likely result in large allowance shortages for many facilities and significant adverse impacts for California businesses and their workers. (CALFP4)

> **Response:** We do not believe that our allocation approach will have adverse impacts for California businesses and their workers. We developed the approach to benchmark stringency after careful analysis of California emissions intensity data and approaches used in other successful cap-and-trade programs.
>
> In selecting benchmark stringency, we are balancing the need to provide adequate transition assistance and minimize leakage with the necessity to meet AB 32's emission-reduction goals and prevent windfall profits through excessive free allocation.
>
> In developing the existing benchmarks we did consider national and international data where available. The energy-based benchmarks assume natural gas as a benchmark fuel and an 85 percent efficient benchmark boiler for steam generation. We believe both of these benchmarks are appropriate for use in a national context. We will consider additional national data as it becomes available.
>
> Furthermore, pursuant to Board Resolution 11-32, the Board directed the Executive Officer to continue to review information concerning the emissions intensity, trade exposure, and in-state competition of industries in California to the recommend changes, if needed.

Glass

C-22. Comment: It was pointed out during our meeting that in some facilities material is used in air pollution abatement equipment for SOx control which can contribute to CO_2 emissions. These emissions have not been reported by facilities in the past and

GPI wanted to know if this needed to be included moving forward and if so how would that effect the benchmark already established as the numbers are not included in the survey data collected to date. ARB staff indicated that they would investigate this issue and get back to us and that if reporting of this emission source would be required, the benchmark would be raised to account for the new data. We ask that CARB clarify this issue for us in writing. To aid in your analysis, please note that reporting of such emissions is required by 40 CFR 98.33(d). (GLASSPI)

> **Response:** Industry-submitted data indicates that only one facility in California employed such a control device. Emissions were small relative to overall emissions from the sector, and when the emissions from that control device were included in the benchmark calculation, the benchmark did not change. Upon further inquiry, the industry found that other facilities in California have, or may have in the future, these control devices. The total emission level from these devices is still small relative to the total sector emissions, approximately 0.1 percent of the total. However, this information may be considered in future rulemakings.

Container Glass

C-23. Comment: Members of GPI are gravely concerned about Cap and Trade and the proposed benchmark set by CARB. We believe it will have an enormous impact on the few remaining container glass facilities left in the state. Twenty years ago, there were 14 container glass manufacturing facilities in California, today there are only five. This shrinkage is the direct result of the high cost of doing business in the State and has resulted in the loss of thousands of jobs and millions dollars in revenue to the State. (GLASSPI)

> **Response:** This comment does not address a change made in the second 15-day changes to the regulation. However, we believe our benchmark stringency is set at an appropriate level to minimize leakage from the glass sector. As we previously have stated, we will continue to monitor leakage risk and recommend appropriate changes if necessary to minimize the risk. Furthermore, pursuant to Board Resolution 11-32, the Board directed the Executive Officer to continue to review information concerning the emissions intensity, trade exposure, and in-state competition of industries in California to the recommend changes, if needed.

C-24. (multiple comments)
Comment: Madera facility employs a state-of-the-art combustion technology and utilizes high levels of cullet which combined result in one of the lowest GHG emission rates per ton of glass produced of any container glass manufacturing facility in the country. The container glass industry in California has been using post-consumer cullet for many years pursuant to the 35 percent recycled content requirement set forth in the California Beverage Container Recycling and Litter Reduction Act, section l4549(b). Our industry should not be punished by limiting or reducing free allocation allowances,

but should instead be rewarded through full allocation of free allowances for these early reduction actions. (SMITHS2)

Comment: The most effective way for CARB to recognize the early reductions achieved by our industry sector is to utilize the emissions data provided to CARB staff for the years 2005-2007 as submitted to CARB in response to its 2009 Glass Container Manufacturers Survey. That Survey includes emissions data prior to industry efforts to further reduce GHG emissions, instead of that data, CARB staff calculated the Benchmark for our industry sector using 2009 emissions data which it collected in a second informal survey. The data initially submitted to CARB in the 2005-2007 comprehensive survey supports an Energy Efficiency Benchmark of 0.31 $MTCO_2E$/ton of glass produced, reflecting GHG emission rates prior to early reduction efforts by our industry sector. We therefore urge that in approving the final rule, CARB amend Table 9-1 of the proposed rule, by replacing the Benchmark value of 0.264 with the value 0.31 in order to properly credit our industry for its early reduction efforts. (SMITHS2)

Comment: GPI strongly urges CARB utilize the 2005-2007 data collected from the first round of surveys which shows a .31 metric tons of CO_2/ton of glass pulled emission rate or in lieu of that provide an amendment to the current benchmark value to add an additional .013 metric tons of CO_2/ton of glass pulled to account for the early action measures. To the extent that staff requests verification of the Survey data, such verification will be submitted upon request. (GLASSPI)

> **Response:** We believe our benchmarks appropriately recognize early action. While all of the data for years 2005-2007 was collected by survey, it is incorrect to state that this is also the case for year 2009 data. Verified MRR data for combustion emissions for 2009 was used to calculate the benchmark, along with data for process emissions and production provided by the industry. This was the most accurate data available. In some cases, due to the economic downturn, data available in the MRR was not representative of typical operation, and would have produced a skewed benchmark. This was not the case for the container glass industry. Therefore, we used the most accurate data available. We will re-evaluate additional data years for use in benchmark calculation as new, high-quality data become available.
>
> The commenters state that the benchmark value calculated from the 2005-2007 survey data would be 0.31, while that calculated using 2009 data is 0.264 in the Regulation, and recommends that we replace the benchmark in the Regulation with 0.31. This comparison is misleading. The benchmark in the Regulation represents ninety percent of the California average, while 0.31 was the average for glass container manufacturers for the period of 2005-2007. Therefore, if we used data from the period of 2005-2007, the average would be adjusted to the ninety-percent level, and the benchmark would be 0.279.
>
> Finally, the commenters state that a value of 0.013 metric tons of CO_2/ton of glass pulled should be added to the benchmark to account for early actions if we

do not change the benchmark in the Regulation to 0.31. It is not clear what assumptions were used to determine the value of 0.013.

C-25. Comment: We are very disappointed CARB will be recommending a California-only benchmark, even though such a benchmark is insufficient to protect the State's container glass facilities from leakage due to national and global competition. (GLASSPI)

Response: We believe the selected benchmark stringency is sufficient to minimize leakage. Furthermore, pursuant to Resolution 11-32, the Board directed the Executive Officer to continue to review information concerning the emissions intensity, trade exposure, and in-state competition of industries in California to the recommend changes, if needed.

Flat Glass

C-26. Comment: Under the harmonization of the MRR rule with federal GHG reporting requirements, CO_2E emissions resulting from carbon in the raw materials used to make glass (i.e., process emissions from glass production) will be included in a glass production facility's total reported CO_2E emissions. This poses a significant challenge for flat glass manufacturers because there are no lower-carbon substitutes for the raw materials used in the production of flat glass. While a higher proportion of cullet may reduce the carbon content of the raw material batch, significantly increasing cullet usage is not a viable option for flat glass manufacturers due to product quality impacts. In this regard, flat glass manufacturing is quite different from other types of glass manufacturing. (PPGI2)

Response: Our understanding is that given a high-quality cullet source, there may still be an opportunity for flat glass manufacturer to increase the use of cullet, albeit most likely less of an opportunity than for the other glass manufacturing sectors. However, this is not the only strategy available to reduce emissions from the industry, as there are opportunities to reduce combustion emissions as well.

Gypsum

C-27. Comment: Comments submitted by the Gypsum Association on the MRR regarding the correct unit benchmarks for gypsum board caused a dialog to occur between the Association and ARB staff regarding the proper definition for stucco. On the basis of the conversations, the MRR now includes a definition for stucco. Since our proposed modification to identify that the benchmark unit for plasterboard production is based on the mass quantity of stucco used to produce salable plasterboard, and incorporates the use of the term stucco, the cap-and-trade regulation should incorporate the definition for stucco that is contained in the Proposed Second 15 Day Modifications for the MRR. We propose that the following definition be added:

“Stucco means hemihydrate plaster (CaSO4●1/2H2O) produced by heating (“calcining”) raw gypsum, thereby removing three-quarters of its chemically combined water.” (GA2)

> **Response:** The addition of the stucco definition was inadvertently left out of the second 15-day revisions to the regulation, but will be incorporated when we make further changes to the regulation. The units have been changed in the Mandatory Reporting Regulation, which is the basis for allocation, so the oversight will not affect the industry’s manufacturing allocation.

C-28. Comment: The listed unit for the proposed benchmarks for plasterboard is incorrect. Our review indicates that the documents posted by the ARB on July 25, 2011, incorrectly identify the unit for the proposed plasterboard benchmark as “Allowances / Short Ton of Plaster Board” in the cap-and-trade regulations and incorrectly identify the production reporting requirement as “the amount of plaster board produced” in the mandatory reporting requirements. The Gypsum Association and its members request that ARB change the relevant references to correctly identify that the benchmark unit for plasterboard production is based on the mass quantity of stucco used to produce salable plasterboard and not the quantity of plasterboard produced. It is noted that the units of the EU ETS benchmark should also be changed to reflect the mass quantity of stucco used to produce plasterboard rather than mass of plasterboard itself as is currently listed in ARB’s 15-day change documents. Specifically, ARB needs to correct the errors in the following sections of the cap-and-trade regulations, and other 15-day change documents:

- Cap-and-Trade Regulations: Subchapter 10, Article 5, Subarticle 9, section 95891. Allocation for Industry Assistance, Table 9-1: Product Based Emissions Efficiency Benchmarks. Units should be changed for the benchmark in the “Plaster Board Manufacturing” activity from “Allowance / Short Ton of Plaster Board” to “Allowance / Short Ton of Stucco Used to Produce Saleable Plasterboard”.
- Appendix B: Development of Product Benchmarks for Allowance Allocation, Table B. Comparison of California and EU ETS Product Benchmarks. Units should be changed for all benchmarks (CA Imperial Units, CA SI Units, and EU ETS) in the “Plaster Board Manufacturing” activity from “…Ton of Plaster Board” to “…Ton of Stucco Used to Produce Saleable Plasterboard.” (GA2)

> **Response:** This change in the benchmark units was inadvertently left out of second 15-day changes to the regulation, but will be incorporated when we make further changes to the regulation. The units have been changed in the Mandatory Reporting Regulation, which is the basis for allocation, so the oversight will not affect the industry’s manufacturing allocation.

C-29. Comment: The base year selected by ARB should reflect both present and future production constraints. The Gypsum Association wants to ensure that the base year that the ARB selects to allocate 2013 allowances for each gypsum board manufacturing plant reflects a fair and reasonable production level. Specifically, the base year should acknowledge both the current economic recession and its impacts on the gypsum board industry and the impact on allocations that will occur when idled capacity is brought back on line at a future date. The Proposed Regulations do not appear to address this very important issue. In May of this year, The Gypsum Association submitted a chart that displays monthly shipments of gypsum board to locations in the State of California for the period 2005 to 2010. This data points out the precipitous decline in shipments in the state during the period noted and reinforces the need for ARB to be judicious when it establishes a base year for the gypsum board manufacturing facilities located in the State of California. The Gypsum Association requests further information from ARB on whether or not this base year has been determined for 2013 and would value the opportunity to enter into discussions with ARB regarding the importance of setting an achievable allocation for 2013 and years beyond. (GA2)

> **Response:** We are unclear what the commenter means with respect to determination of 2013 as a "base year." The true-up term in the allocation equation ensures allocation is based on actual production for any given year. If the level of production goes up, the amount of free allocation to the facility increases. Conversely, if production goes down, the level of free allocation decreases. We modified section 95891(b) to clarify our approach.

C-30. Comment: The Industry Assistance Factor for the Gypsum Product Manufacturing Industry in Table 8-1 should be higher. The Gypsum Association believes that the annual Industry Assistance Factor for the Gypsum Product Manufacturing (GPM) industry should be 100 percent for the entire period 2013 through 2020. It is our position that in assigning a "medium" leakage risk classification to the GPM industry the ARB has understated the risk leakage for the industry. In assigning a leakage risk classification to an industry, ARB applies a methodology that assigns equal weight to the concepts of emissions intensity and trade exposure. While we are of the opinion that the GPM industry should not be evaluated as an "emissions intense" industry, we are concerned that ARB may be understating the local trade exposure risk to the industry. Gypsum board is a consistent quality, commodity material that is often transported by rail. As a consequence, gypsum board can be produced in a specific state or country and transported over land and sold in a different state or country. While ARB is correct in its assessment that gypsum board is not readily imported from or into the State of California from locations outside of North America, it is our opinion that the Appendix K methodology and its reliance on national and regional data may be understating the potential intra-regional trade exposure for gypsum products in the State of California. Our concern is that ARB has not taken this attribute fully into account when assigning the risk leakage classification to the GPM industry. (GA2)

> **Response:** This comment falls outside the scope of the second 15-day changes to the regulation. However, we believe that we correctly classified the gypsum sector and related activities as facing a "medium" risk of leakage.

Hydrogen

Benchmark Stringency

C-31. (multiple comments)
Comment: The allocation benchmark for hydrogen produced by industrial gas manufacturers must be equitable. The allocation benchmark for hydrogen must be based on a consistent performance challenge with all other product-based benchmarks. (IGPACC2)

Comment: Air Products submitted comments to the First 15-Day Amendments to the cap and trade rule indicating the inequitable treatment that would result from a hydrogen benchmark derived from a small and biased subset (6 of 26) of the hydrogen production facilities operating in the state. CARB staff has indicated it was not able to assemble the necessary data from all these production facilities with which to derive a representative benchmark. As such, Air Products endorses CARB's decision to instead apply the EU ETS hydrogen benchmark, one that was derived from a more representative cross-section of production facility sizes, ages and efficiencies. This decision, coupled with CARB's commitment (beginning with the Second Compliance Period) to apply the refinery benchmark derived under the ETS program, provides greater assurance that the allowances allocated to hydrogen production under the program will be the same, regardless of whether the production is undertaken by a refinery or an associated independent industrial gas facility. Since the ETS hydrogen benchmark was derived from within the ETS refinery benchmark, it shares the same large (98 facilities) database from which to obtain emission intensity data and derive the performance curves which define the benchmark performance challenge. Further, adoption of the ETS refinery benchmark ensures proper treatment for refinery steam consumption, regardless of whether the steam is self-produced or imported from an independent supplier. This facilitates fair treatment when the cost of carbon is imposed on the production of imported steam. In these ways, equitable treatment is preserved, regardless of the ownership structure for the production activities (hydrogen and steam) supporting refineries. Air Products supports the joint application of the two ETS-derived benchmarks. (APC3)

Comment: The allocation benchmark for hydrogen must be based on a consistent performance challenge with all other product-based benchmarks. CARB describes the benchmark stringency criteria used for deriving product-based benchmarks from actual facility performance data in Appendix B of the First 15-Day Amendment package issued in July 2011. On page 3 of that document, CARB described a targeted level of stringency created by evaluating each industrial sector's production-weighted average emissions intensity during a historical base period and targeting the benchmark to allocate 90 percent of this level per unit product. CARB further refined this approach for sectors where the 90 percent performance challenge would set the benchmark at a level that was more stringent than the current emissions intensity of any existing Californian facility. For the sectors for which this occurs, the benchmark would be based on the "best-in-class" value. In contrast, the EU ETS benchmark process employs a benchmark stringency defined as "the average of the top 10 percent" emission intensity for production facilities in that sector. Depending on the shape of the performance curve for a particular sector, this stringency can represent various degrees of performance challenge. It is this fundamental difference in benchmark stringency criteria between the California and EU ETS programs that leads to a fairness issue in the application of the ETS hydrogen benchmark "as is" under the California program. In this instance, the "performance challenge" inherent in the ETS hydrogen benchmark is stricter than that which CARB is employing for the other product-based benchmarks under the California program. This fairness issue can be easily remedied by making an adjustment to the benchmark value to reflect a performance challenge consistent with the State's default 90 percent standard approach. Correction of the ETS hydrogen benchmark to reflect a consistent 90 percent performance challenge is straightforward. The adjustment factor is just the ratio of the two alternative performance challenges, in this case, 0.9/0.797, or a factor of 1.13. By multiplying the proposed ETS hydrogen benchmark value of 8.85 tonnes CO_2-e/tonne hydrogen by the adjustment factor, a hydrogen benchmark reflecting the states default 90 percent standard would be 9.99 tonnes CO_2-e/tonne of hydrogen. Air Products strongly recommends CARB adjust the proposed hydrogen benchmark to the 9.99 tonne CO_2-e/tonne hydrogen produced in order to provide fairness with respect to the economic impact of the cap and trade program across all California industrial sectors. Omitting such an adjustment will serve to reduce the sectors competitiveness, contrary to the intent of the industry assistance recommended under the ISOR. (APC3)

Response: We believe that benchmark stringency should reflect the emissions intensity of highly efficient, low-emitting facilities within each sector. This is equivalent to the stated policy goal of the European Union's in the Emissions Trading Scheme's benchmarking work.

Within each sector, facilities with efficiencies better than the benchmark, will be receiving more allowances than they will need, and can sell their excess allowances. Less-efficient facilities will need to purchase allowances to fulfill their compliance obligations.

We believe the hydrogen benchmarks incorporated in the cap-and-trade regulation accomplish our goal, in that there are Californian facilities with emissions intensity better than the selected benchmark value.

We recognize that there is a difference in the performance challenge created by selecting the average of the top decile (the average of the best 10 percent) as done in the EU and 90 percent of the total sector average emissions intensity. We believe the EU's approach to setting benchmark stringency is preferable when there is a robust data set for each sector.

However, the lack of robust North American data sets for all covered industries is what led us to develop the "90 percent of average or best-in-class" approach that relied heavily on California data.

Liquid Hydrogen

C-32. (multiple comments)
Comment: Liquid hydrogen should receive an independent benchmark and should be categorized as a high leakage risk. (IGPACC2)

Comment: The September 12, 2011, version of the cap-and-trade regulation purposefully established a distinction between liquefied and gaseous hydrogen products, but assigned the same benchmark value to both: 8.85 Allowances. Praxair respectfully disagrees with this position for three reasons. First, while liquefied hydrogen is a more electricity intensive product than gaseous hydrogen, there are also direct emissions attributable to the liquefaction process (i.e. converting gaseous hydrogen to liquefied hydrogen). Liquefied hydrogen plants are smaller than gaseous hydrogen plants, and as such are not as efficient as gaseous hydrogen production. Moreover, there are also inefficiencies associated with the liquefaction process and with handling liquefied hydrogen after the liquefaction process. Second, it is not clear that R.11-03-012 will be resolved in time to allow meaningful resolution for liquefied hydrogen producers. The recent Scoping Ruling in R.11-03-012 projects that a proposed decision will be available in May of 2012, but the actual release and final adoption of a proposed decision could be much later, especially given the scope of issues and controversial nature of GHG cost allocation. Meanwhile, the cap-and-trade program will effectively start when the first auction takes place in July 2012. This timeframe provides liquefied hydrogen producers with little certainty regarding how they should participate in the initial auctions. Third, R.11-03-012 will not consider cost allocation decisions by publicly owned utilities (POU). GHG cost allocations decisions are left to the discretion of the POUs, and liquefied hydrogen producers in POU service territories may never receive any rate reduction for their indirect emissions costs. In sum, Praxair believes it is not appropriate to wait to develop an accurate efficiency benchmark until R.11-03-012 is resolved. Therefore, Praxair requests that before the start of the program, CARB conduct a benchmarking study of the two facilities located in California to determine an accurate emission profile for liquid hydrogen production employing the Steam Methane Reformer (SMR) technology. (PRAXAIR3)

Comment: Praxair believes that further analysis of liquefied hydrogen production is necessary to ensure that this product not unfairly disadvantaged in relation to out-of-state competitors. Moreover, the Board’s recognition of the need for an accurate leakage risk assessment and efficiency factor for liquefied hydrogen will help preserve jobs at the two liquid hydrogen facilities in the State and in the industries that are dependent on the products availability (aerospace, biofuels, fuel cell vehicles, electronics and metals). Recognition will avoid the unintended emissions impacts from competitive product shipped into the State by truck. (PRAXAIR3)

Comment: Praxair is very concerned that the September 12, 2011, version of the cap-and-trade regulation does not recognize the unique leakage risk for liquid hydrogen production. Liquefied hydrogen should be characterized as a high leakage risk because the liquefaction process can be replicated in states or countries adjacent to California, liquefied hydrogen is readily transportable across California's borders, and out-of-state liquefied hydrogen producers will not be subject to a GHG emissions obligations. To avoid the detrimental impact to in-state employment, Praxair requests that CARB re-evaluate the leakage risk for liquefied hydrogen production. Specifically, Praxair requests that the Board's resolutions specifically acknowledge that liquid hydrogen production be viewed differently from production of gaseous hydrogen in terms of allocation and leakage risk. (PRAXAIR3)

Comment: Liquid hydrogen is a different product from the gaseous hydrogen used in refining applications. While both liquid and gaseous hydrogen are very energy (and emission) intensive, liquid hydrogen serves different end-markets, is easily transported and is subject to trade (currently, primarily exports) between California and other non-WCI states and provinces not subject to a comparable cost of carbon. If CARB were to apply the energy/emissions intensity and trade exposure analysis intended under Appendix K of the December 2010 Proposed Rule, we believe the analysis will yield a leakage risk aligned with those industry sectors currently designated as high risk, rather than the medium risk CARB has proposed for liquid hydrogen. (APC3)

> **Response:** We recognize that purchased electricity used in the production of liquid hydrogen could potentially create indirect carbon costs. We will revisit the issue of carbon costs embedded in purchased electricity once the California Public Utilities Commission Proceeding addressing utility costs and revenue issues associated with greenhouse gas emissions (R.11-03-012) concludes. We will also evaluate the carbon costs faced in publicly owned utility service territories once the governing boards of these utilities determine how carbon pricing will impact industrial electricity rates.
>
> In developing the product benchmarks, we avoid differentiating by technology, fuel mix, size and age of the facility, climatic circumstances, or raw material quality wherever possible. This allows all methods of greenhouse gas abatement to remain available to the covered entities. Therefore, we do not agree that a smaller hydrogen production facility deserves a more generous benchmark based solely on the size of the facility.
>
> We look forward to continued dialogue with stakeholders relating to the leakage risk associated with the market for liquid hydrogen. We will continue to evaluate this issue and will recommend appropriate changes, as necessary, to the assigned leakage risk in a future rulemaking.

Feedstocks Used for Hydrogen Production

C-33. Comment: CARB has proposed allocating allowances for gaseous and liquid hydrogen production based on a benchmark of 8.85 allowances per metric ton of hydrogen gas. The proposed benchmark is based on the benchmark for hydrogen production adopted under the European Union (EU) Emissions Trading System. The proposed benchmark, does not account for the carbon content of the different feedstocks used in hydrogen production, which may be either refinery fuel gas or natural gas. Air Liquide is not opposed to CARB's reliance on the EU benchmark in this phase of the regulatory process, but it should be adjusted to account for the feedstocks used by particular facilities. Many hydrogen production facilities use natural gas as a feedstock. However, in California, some hydrogen producers, including Air Liquide, use refinery fuel gas as a feedstock. Refinery fuel gas has higher carbon content and creates greater emissions than natural gas when used as a feedstock, but the use of refinery fuel gas in the hydrogen production process actually generates lower overall CO_2 emissions because the refinery fuel gas would otherwise be flared and burned by the refinery. The use of refinery fuel gas also avoids the emissions associated with extracting, purifying and transporting natural gas to the hydrogen plant, as the refinery fuel gas is a by-product of the petroleum refining process. A hydrogen plant's productive use of refinery fuel gas that would otherwise be flared is therefore environmentally beneficial, and should not be discouraged. Unless CARB addresses the differing feedstocks used by California hydrogen production facilities, market distortions will result. Again, there is a simple solution that will encourage the use of refinery fuel gas, with its attendant benefits, and will avoid market distortions. Air Liquide requests that the Board direct staff to develop adjustments to the hydrogen production benchmark that address the feedstock used by the producer. For hydrogen plants that use natural gas as a feedstock, the proposed benchmark is appropriate. For hydrogen plants that use refinery fuel gas, an adjustment factor for the benchmark that accounts for the greater carbon content of refinery fuel gas should be developed. Air Liquide would be pleased to work with CARB staff to develop such an adjustment factor. (ALLI2)

> **Response:** In developing the product benchmarks, we avoid differentiating by technology, fuel mix, size and age of the facility, climatic circumstances, or raw material quality wherever possible. This allows all methods of greenhouse gas abatement to remain available to the covered entities. As the commenter notes, the choice of refinery fuel gas is a more greenhouse gas-intensive feedstock when compared to the use of natural gas in the production of hydrogen. We do not wish to incentivize a switch to this feedstock so we did not differentiate the feedstock based on feedstock type.

Natural Gas

C-34. Comment: Section 95870(d)(2) and 95890(c) should be included and not deleted. Since ARB has not yet decided how to allocate allowances to natural gas utilities for the protection of their small customers as evidenced by section 95893 being "Reserved for Allocation to Natural Gas Distribution Utilities for Protection of Natural Gas Customers," it is premature to delete sections that support an allocation to natural gas utilities on behalf of their customers. SoCalGas and SDG&E reiterate their position that ARB should allocate a significant percent of the sector emissions to gas local distribution companies (LDC) for the benefit of their customers when the sector enters the cap-and-trade in 2015. Such an allocation will protect low income customers and small business, will avoid double payment by LDC customers for energy efficiency and research and development programs, and will avoid rate shock. Gas LDCs are rate regulated in such a manner that allowance value can be designated for the benefit of the small natural gas consumers who face the incidence of the carbon price. ARB should retain sections reserved for an allocation to natural gas utilities until ARB has adequately considered the issue, just as it has done in Section 95893. Modify section 95870(d)(2) as follows:

> <u>(2) Reserved for Natural Gas Distribution Utilities.</u> (SEMPRA4)
>
> **Response:** We did not add the language requested by the commenter. However, as indicated in the Staff Report and Board Resolutions 10-42 and 11-32, we are continuing to evaluate all proposals presented. We will initiate a public process to determine how, and if, allowances should be allocated for natural gas distribution utilities, prior to coverage of the sector beginning in 2015. We note the importance of transparent price signals for fuel consumers in achieving reductions in this sector.

Oil and Gas

C-35. (multiple comments)
Comment: WSPA appreciates ARB's replacement of the heavy oil/light oil approach used in the prior 15-day change package with a thermal/non-thermal approach. However, several serious concerns still remain:

- The proposed oil and gas extraction sector benchmarks (0.0816 for thermal and 0.0082 for non-thermal) are derived from a process that remains undocumented by ARB and thus unsubstantiated to upstream producers. There has been no published protocol or methodology describing how the benchmarking calculations were performed. Further, no data, calculations or other information used to derive the benchmarks have been published. This lack of transparency has made it impossible for upstream oil and gas producers to examine the approach, to duplicate benchmark results or validate the ultimate conclusions.
- ARB has indicated that the benchmarks are based on data from MRR reports and a voluntary 2007 survey. However, the 2007 data has not been subject to any form of validation/verification, and would not meet verification protocols that are required for MRR data.
- EPA's 40 CFR Part 98, Subpart W language, which has been included into MRR, will require reporting emissions from equipment types that were not included in ARB's upstream oil & gas extraction sector benchmark calculations. ARB has not addressed this inequity.
- The data ARB used to determine the oil and gas production benchmarks failed to incorporate indirect GHG emissions, e.g., those emissions associated with electricity and heat used/produced in the production process. For California oil and gas producers, electricity and heat consumed in oil and gas production can vary widely, and for some facilities represents a significant portion of energy consumed. The lack of appropriate consideration in the calculated benchmarks represents a systemic error in ARB's approach. This error will likely have

significant impact when allowances are allocated, which will likely create an incentive for companies to favor purchasing power from the grid and/or outsourcing thermal purchases.

WSPA recommends that ARB work with industry to ensure the appropriateness and accuracy of the petroleum and natural gas sector benchmark values through confirmation of the reported and verified data and the calculation methodologies. (WSPA4)

Comment: Other than the initial guidelines on how sector benchmarking would identify allowance allocation to various industries, CARB staff has not provided information on the individual protocols. For example, the proposed oil and gas extraction benchmarks (0.0816 for thermal and 0.0082 for non-thermal) are derived from a process that remains a “black box” to the regulated community. The generation of these benchmark values cannot be duplicated by the public sector. The methods and protocols used by CARB staff should undergo the same scrutiny and verification that all of industry is required to follow for reporting emissions. (CIPA2)

Comment: ARB's September 12 changes contain the second set of changes to benchmark values since July 2011, leaving little time to analyze and understand how these evolving benchmarks were derived. Occidental has not been able to confirm that the recent changes to the benchmarks are based on a complete and accurate representation of any of its facilities' greenhouse gas emissions. Occidental's facilities are complex and the Cap and Trade rule is not sufficiently definite to determine whether ARB segmented comparable Occidental facilities based on appropriate consideration of key operational parameters. The process used by ARB staff to develop the benchmarks has not yet fully demonstrated adherence to fundamental principles of equity, transparency and reproducibility, and has not shown that it fulfills ARB's objective of minimizing leakage. The proposed benchmarks are derived in a way that remains a "black box" to upstream producers. There has been no published protocol or methodology describing how staff performed the benchmarking calculations. Further, essentially no data, calculations or other information used to derive the benchmarks have been published by ARB staff. This lack of transparency has made it impossible for Occidental and other upstream oil and gas producers to examine the approach taken by Staff, to duplicate benchmark results or validate Staff conclusions. Further, ARB Staff has indicated that the benchmarks are based on data from California's regulation for greenhouse gas emissions reporting (MRR) and a voluntary 2007 survey. However, the 2007 data have not been subject to any form of validation/verification, and would certainly not meet verification protocols that are required for MRR data. Occidental believes that the benchmarks should be based on the most recent verified MRR data. (OPC3)

Comment: The unverified data CARB used to determine the oil & gas production benchmarks did not incorporate indirect GHG emissions, e.g., emissions associated with electricity and heat used/produced in the production process. For California oil & gas producers, the electricity and heat consumed in their operations can vary widely.

For some facilities this represents a significant portion of energy used. Not considering this energy consumption in the calculated benchmarks is a gross error in ARB's approach and will skew the allocation with harmful economic repercussions. This error will have significant impact on how allowances are allocated. In fact, ARB currently is allocating no allowances to Cogeneration facilities in California and the indirect energy use for some of these facilities represents most of their GHG emissions. Coupled with the "haircut", there will be operators who fold because their margins will not support these increased costs and there is no opportunity to pass the costs along. This inequity must be corrected. (CIPA2)

Comment: We appreciate that ARB has adopted an energy based upstream benchmark that recognizes California's unique oil and gas resources. However, since much of the rulemaking and public participation was delayed in 2011, it is not clear how the actual calculations were performed. Since benchmarking data were gathered before verified data collection was completed, and because the benchmark is an average of industry information, it is impossible to reproduce the data and the table in the rulemaking. We understand that ARB is willing to work with stakeholders to ensure that the benchmark, as well as the assumptions behind the supporting data, are both consistent and correct, and we look forward to working with ARB on this issue. (CHEVRON4)

Comment: The data ARB used to determine the oil & gas production benchmarks failed to incorporate indirect GHG emissions, e.g., those emissions associated with purchased electricity and heat used/produced in the production process. The lack of appropriate consideration in the calculated benchmarks of the differences in the way electricity is used and produced between California oil and gas facilities represents an important, systemic error in ARB's approach. ARB's failure to capture in the benchmarks the full GHG emissions burden for equipment powered by electricity purchased from outside a facility creates an arbitrary bias against any facility using electric equipment powered by electricity generated on-site. This error will likely have significant impact in how allowances are allocated, creating an incentive for companies to shut-down on-site electricity generating units (even those operating at marginal heat rates equivalent to that of a state-of-the-art combined cycle gas turbine facility) in favor of purchasing power from the grid and/or outsourcing thermal purchases . Benefits provided by on-site generation include reduced GHG emissions resulting from lower effective heat rates (generation efficiency), reduced transmission losses, increased electric system resource adequacy, and reduced spinning reserve and peaking capacity requirements. In short, ARB's failure to develop an accurate benchmark—one that reflects both direct emissions and those emissions associated with grid-sourced electricity—will likely spur more imports of out-of-state electricity, place additional load on the state's transmission system and will not result in any greenhouse emissions reductions. Certainly, this cannot reflect the intent of ARB. EPA's 40 CFR Part 98, Subpart W rule for GHG reporting from upstream petroleum and natural gas systems, which has been incorporated into ARB's GHG emissions reporting rule, will require reporting emissions from more equipment types and use a facility definition that that was not included in ARB's upstream oil & gas extraction sector benchmark calculations.

The consequences of these inconsistencies and the impact of the significantly expanded geographical scope in the EPA Subpart W facility definition have not been thoroughly addressed by staff during the rulemaking process. These reporting anomalies will compound the errors in the 2007 voluntary reporting data and the other benchmarking issues noted above. Occidental alone, and as a member of the Western States Petroleum Association (WSPA) and the Energy Producers and Users Coalition (EPUC), has met several times with ARB staff to address specific concerns and propose approaches to resolve these matters. For additional information, Occidental references and incorporates herein its earlier comments (dated November 15, 2010, December 15, 2010 and August 11, 2011), and supports and incorporates herein the related comments submitted by WSPA and EPUC in response to the 15-day changes issued July 25 and 27, 2011 under the cap and trade rulemaking. Occidental recommends that ARB staff work with the oil and gas industry to ensure the appropriateness and accuracy of the sector benchmark values through confirmation of the reported and verified data and the calculation methodologies. (OPC3)

Response: Multiple commenters state that the benchmarks did not incorporate indirect GHG emissions. This is not correct. As explained in Appendix B to the first 15-day changes to the regulation, the product benchmarks account for indirect carbon costs (generated due to indirect emissions). Adjustment factors were used to account for the indirect carbon costs embedded in heat purchased or sold and electricity sold. An adjustment factor was not made for power purchased in establishing the product-based benchmarks. This is because purchased power from a utility may not create an indirect carbon cost in all California utility service territories. It is ARB's goal to see a carbon price properly embedded in all utility rates. We will revisit this issue after the CPUC proceeding R.11-03-012 concludes.

We will continue to work with the CPUC and stakeholders to ensure that the cap-and-trade carbon pricing creates the correct incentives for efficient combined heat and power. We disagree that there is "no opportunity to pass the costs along" in the price of heat or power sold from these facilities. The Qualifying Facilities and Combined Heat and Power Settlement will guarantee some level of carbon cost pass-through for many combined heat and power facilities.

We recognize concerns about the transparency of benchmark development. However, production data and energy purchases and sales information for each facility were collected in a confidential fashion. Because we cannot share data submitted confidentially, we cannot publish the full benchmarking calculations.

We believe we have provided sufficient detail regarding our benchmarking approach in the Staff Report and Appendix B to the first 15-day changes to the regulation, as well as through continued dialogue with stakeholders, to provide an understanding of the results of our analysis. Further, publication of this type of data could lead to a variety of market manipulations.

We disagree that the additional emissions captured by the move to U.S. EPA Subpart W coverage for the sector will significantly change the benchmark values. However, we will continue to work with the oil and gas industry to ensure the appropriateness and accuracy of the sector benchmark values through future rulemakings as needed.

C-36. (multiple comments)
Comment: The latest regulation modification has further loosened requirements for oil drilling (extraction). It provides more lax requirements for the most intensive oil drilling operations, which effectively subsidizes and encourages these practices. Wilmington California, already the location of severely concentrated pollution sources, is also the third biggest oil field in the U.S. The cap and trade regulation provides such practices as 100 percent free allocations throughout the entire cap and trade program through 2020. It also provides more credits to higher polluting practices compared to other types of drilling (for example, Table 9-1 now allows thermal drilling ten times the allowances/barrel compared to non-thermal drilling). This type of thermal extraction that is being encouraged and subsidized by the cap and trade regulation, provides extra, and free allocations. CARB should absolutely remove the free, and increased allocations that are present at 100 percent throughout the entire cap and trade program to 2020. The most intensive practices, located in the most polluted communities, which are low-income communities and communities of color, will receive the greatest subsidies to pollute. This is environmental racism and violates California law. Oil drilling in Wilmington is a perfect example of operations that cause CO_2 emissions where CARB has the ability to reduce co-pollutant emissions, especially those not addressed by local regulators. Instead, CARB is allowing these operations extra and free credits for these polluting operations. CARB must evaluate the impacts of the ten times higher allocations for the most polluting practices. (CBE3)

Comment: CARB has revised an initial proposal to grant allocations based on crude type to, instead, proposed benchmarks with an almost 10 fold increase for producers that use a highly carbon and emissions intensive production process, steam injection, compared to less carbon and emissions intensive production processes of air and water injection or primary production. There is no justification for this perverse incentive to increase emissions, which conflicts with the goals of AB 32 to reduce GHG emissions and associated criteria pollutant emissions and transition industry to cleaner alternatives. In addition, this incentive would almost entirely benefit heavy crude oil with higher refining criteria and GHG emissions as noted earlier. Finally, the proposal would be difficult to implement due to questions about which underground crude oil production zones are subject to the influence of underground steam injection wells. Of greatest concern, a more generous benchmark for the carbon intense use of steam could lead to increased use of steam, particularly in wells that are not steamed presently, in order to qualify for the nearly 10 times higher level of free allowances. The best approach is a flat benchmark of 5 grams CO_2/MJ (or 0.020 to 0.025 allowances/barrel), with bonuses available to companies that implement advanced technology such as solar steam production. While we prefer a single process-neutral benchmark for this sector, the original proposal of lower subsidies for light oil and higher subsidies for more carbon intensive heavy crude is more appropriate than the current proposal to scale up free GHG allowances based on the carbon intensity of the production process. CARB should allocate allowances based on a flat benchmark of 5 g/MJ, and commence the necessary technical studies to reassess the leakage risk for domestic captive producers of petroleum output. (KUSTIN18)

> **Response:** As noted in Appendix J to the Staff Report, although ARB prefers to apply a “one product, one benchmark” principle, an exception was made for oil extraction because non-thermal alternative techniques are not usually substitutable in the wells where thermal enhanced oil recovery (EOR) is applied.
>
> We disagree that this approach creates a subsidy for more emission intensive processes. As the commenter notes, solar thermal extraction techniques are under development. These techniques produce steam to extract oil that requires thermally enhanced EOR with a much lower greenhouse gas footprint. This extraction technology will be heavily incentivized under the current benchmarking approach.
>
> We do not believe the allocation approach provides “100 percent free allocations throughout the entire cap and trade program through 2020.” Rather, we begin with ambitious benchmarks that reward only the current best performers. The allocation per barrel then declines approximately two percent per year due to the cap adjustment factor found in Table 9-2.
>
> We will continue to monitor emissions leakage risk for the oil and gas sector in the context of an evolving global climate change policy framework.

Paper

C-37. Comment: CARB is proposing to use product based benchmarks as the basis of allowance allocations for the Paperboard sector. As discussed in the comments submitted by AF&PA on December 14, 2010, an industry-wide analysis of pulp and paper manufacturing showed no correlation between greenhouse gas emissions and product type; therefore, we support the use of actual emissions as the basis of allowance allocations. (TI2)

> **Response:** This comment falls outside the scope of the second 15-day changes to the regulation; therefore, no further response is needed. Please refer to the response in Chapter III, starting with Comment C-80.

C-38. (multiple comments)
Comment: CARB established product benchmarks for both products made at the Ontario Mill, linerboard and medium. Since the sample size for these two products (one and two mills, respectively) is so small, we do not believe it is appropriate to establish product based benchmarks, instead it would be more accurate to use actual emissions for allowance allocations. (TI2)

Comment: CARB used data from the Ontario Mill to establish product benchmarks even though the April 2011 decision on the European Union's Emissions Trading Scheme (EU ETS) for the paperboard sector states that it is not feasible to assign GHG emissions to individual products using data from mills where multiple products are produced. Since the Ontario Mill is the only producer of linerboard, there would be no valid data to support a product based benchmark for this activity and actual emissions should be used. (TI2)

> **Response:** We believe it is consistent with the goal of AB 32 to include as many industrial activities as possible under product-based benchmark to minimize leakage. Under the product-based approach free allocation is based on product level that will be updated annually to ensure that the compensation is provided as production increases. We disagree that historical emissions would form a better basis for allowance allocation. Allocating based solely on historical emission levels does not create the proper incentives to minimize leakage.
>
> For the sectors for which there are only two facilities, the best facility's historical performance level is considered to be "best in class." At this point, we are not aware of any robust national emissions intensity data set available for the paper sector. The lack of robust North American data sets for all covered industries is what led us to rely heavily on California data. We will continue to evaluate benchmark stringency across all sectors and may propose changes in future rulemakings should sufficient high-quality data sets develop.

C-39. Comment: CARB developed and revised the product benchmarks for the Paperboard sector without providing any supporting documentation in the proposed rulemaking; therefore, we do not have sufficient information to provide specific comments on the numerical values themselves. (TI2)

> **Response:** We recognize concerns about the transparency of benchmark development. However, production data, energy purchases, and sales information for each facility were collected in a confidential fashion. Because we cannot share data submitted confidentially, we cannot publish the full benchmarking calculations.
>
> We believe that we have provided sufficient detail regarding our benchmarking approach in the Staff Report and Appendix B to the first 15-day changes to the regulation, as well as through continued dialogue with stakeholders, to provide an understanding of the results of our analysis.

C-40. Comment: We are pleased that CARB is proposing modifications which clarify the definition of Tissue manufacturing and the products included therein. We are also pleased that CARB staff acknowledges that individual facilities may produce multiple products which span various industrial sectors and activities, and as such have provided their inclusion in the Industry Allowance Allocation methodology. Additionally, we are pleased that CARB staff has been receptive to industry input which clarifies that paper products manufacturing employs differing production technology and that there are distinctions between conventional and Through-Air Drying (TAD) paper making processes. (PGPPC2)

Response: Thank you for your support.

C-41. Comment: We are deeply concerned with staff's conclusion that tissue produced from TAD and conventional paper making have a reasonably comparable functionality. We believe that these technologies produce substantially different products. As previously communicated, we agree that CARB should assign emissions intensity benchmarks based on different products between or within industrial facilities. As such, we respectfully urge CARB to recognize the functionality differences between TAD and conventional tissues and thus appropriately assign different emissions intensity benchmarks for each. At a minimum we encourage CARB to define what constitutes sufficiently different product functionality such that presumably similar products can be evaluated to determine if different benchmarks should be applied to each. We continue to believe that our Oxnard facility should be assigned an allowance emissions intensity product benchmark unique to Through Air Drying tissue manufacturing. (PGPPC2)

Response: We worked with stakeholders to assess different technologies used to manufacture tissue (e.g., conventional and through-air drying (TAD) processes), and found that final products that use TAD are lighter, fluffier, and more absorbent. However, the functionality of the product is still the same despite these differences. Therefore, we believe that it makes sense to group tissue products, regardless of the technology. We intend to continue working on the tissue sector to further investigate this issue.

Refineries

C-42. Comment: The change to oil refinery benchmarks in the latest cap and trade regulation modifications allows increased emissions from oil refineries, which is are the largest industrial source of GHGs in California and in the cap and trade program. This sector is also is a major emitter of toxic emissions and smog precursors, and located mostly in low income communities of color. Cap and trade is squandering the opportunity of AB 32 to clean up this industry. Moreover, because the credits would be mostly given away for free, the regulation would both increase the current massive, record-breaking profits for this sector and also fail to force or even encourage emission reductions. (CBE3)

Response: We disagree. The cap-and-trade program will provide a robust incentive for greenhouse gas emission reductions in the refining sector. During the regulatory development process, we also evaluated the potential for localized increases in co-pollutant emissions in impacted communities due to a cap-and-trade program to the best of our ability. The findings of this analysis can be found in the *Staff Report: Initial Statement of Reasons* and its Appendix P: Co-Pollutant Emissions Assessment. Since the distribution of changes in co-pollutant emissions resulting from the cap-and-trade program are dependent on how individual facilities choose to comply with the program, we evaluated how co-pollutant emissions could change in three hypothetical scenarios within four environmental justice communities—Wilmington, Oildale/Bakersfield, Richmond, and Apple Valley/Oro Grande. Under the three hypothetical scenarios, we found that co-pollutant emissions could, in the absence of district permits and existing controls, increase or decrease a very small amount. However, most compliance approaches are expected to result in a reduction in co-pollutants through increased efficiency and decreased combustion of fossil fuel. It is important to note that the mere presence of a cap-and-trade program for greenhouse gas emissions will not weaken or reduce facility specific requirements or permits for co-pollutants. All facilities will continue to be subject to existing local ordinances and rules.

C-43. Comment: ConocoPhillips supports ARB's proposal for New Entrants. There is no definition of New Entrants provided in the definitions section of the regulation. We will assume that this also applies to very significant expansions of a facility that have or will require CEQA review and exceed a significant threshold that is considered and approved by the Executive Officer. For the refining sector, ConocoPhillips recommends a threshold of 10 percent increase in clean product volume (gasoline, diesel, jet fuel) or a 10 percent increase in crude capacity. WSPA has also presented a similar recommendation to ARB staff. (CONOCO3)

Response: We thank you for your support. However, we do not agree with your interpretation of the term "new entrants" to be inclusive of facility expansions. We did not add an expansion threshold to the first period refining allocation approach. The CWT approach used in the second and third compliance period recognizes facility expansion due to updated measurement of facility throughput.

C-44. Comment: Among the various modifications made to the proposed regulation was a dramatic change in the methodology for distribution of allowances to individual facilities in the refining sector. This change in methodology provides a significant departure from the previously proposed "Simple Barrel" approach. WIRA believes that the Simple Barrel approach recognized those facilities which produced refined product with the lowest GHG per unit volume and that that approach should have been kept in the regulation. But WIRA also understands CARB staff's view that the diverse and individualized nature of the refining industry does not lend itself to a single, simple output-based benchmark. As such, the newly proposed allocation methodology for the first compliance period appropriately bifurcates the refining sector by the complexity level of the affected facilities. This two-tier approach prevents the smaller, less capitalized refiners from being disadvantaged through the use of an allocation methodology metric not based on GHG efficiency. The new First Compliance Period methodology for smaller, less complex refiners is outlined in section 95891(d)(1). These equations provide California's smaller refiners with the basic assistance necessary to transition into this new program. WIRA supports the regulatory requirement for the Executive Officer to determine the representativeness of a facility's baselines and/or EII prior to allowance allocation. This determination is a key component of the two-tier system. Inclusion of WIRA members into an EII approach sponsored by the Western States Petroleum Association (WSPA) would have been inappropriate and would have placed an artificial competitive disadvantage on them. (WIRA4)

> **Response:** We thank you for your support. Simple refineries that do not have an EII value or those without a representative EII value as determined by the Executive Officer are allocated to using the "simple barrel" product benchmark proposed in the first 15-day changes to the regulation for the first compliance period. The value for this simple benchmark was updated from 0.0465 allowances/barrel of primary refinery products to 0.0462 allowances/barrel. This change was made to reflect additional data provided by covered refineries and the inclusion of 2010 data in the development of the benchmark. A limit on the amount of allowances that a facility can receive was imposed based on historical emission levels, consistent with stakeholder comments. This approach will prevent a facility from receiving excessive rewards due to free allocation under the simple barrel metric.

C-45. Comment: A key aspect in determining allocation levels for both the refining sector and individual non-EII refiners is the definition of a primary refinery product. This definition is used to establish the sector benchmark, and this benchmark has been adjusted in these revisions. CARB staff acknowledges in Appendix A (footnote #2) that the dataset for establishing the sector benchmark will be monitored and could be changed as needed. WIRA recommends that additional analysis be conducted regarding inclusion of bunker fuel for large oceangoing vessels into the definition of a Primary Refinery Product. (WIRA4)

> **Response:** We do not currently believe that bunker fuel represents a primary refinery product that is in need of free allocation to prevent leakage risk. However, beginning with the 2011 data year, ARB will collect detailed, third-party verified, refinery product data as part of the effort to monitor for emissions leakage in this sector. We will monitor the production of bunker fuel in the state using this data set and consider changes to free allocation as needed to address any potential leakage issues.

Leakage Risk

C-46. (multiple comments)
Comment: CARB is overestimating the likelihood of leakage risk, especially in the refining sector, and this is resulting in the subsidization (via free allocations) of carbon intensive industries. There are significant costs from the free allocation of valuable allowances since these public monies could instead be spent on lowering the costs of the cap-and-trade program. A reassessment of leakage risk must be undertaken to

take into account transportation costs and the ability of non-Californian companies to compete with California producers. As the Economic and Allocation Advisory Committee (EAAC) report suggests leakage concerns are very unlikely to occur unless carbon prices reach over $50/ton. In addition, subsidies for carbon intensive products and processes are a barrier to cleaner alternatives. CARB should redo the leakage risk analysis to fully consider the cost differential between imports and California production, the barriers to entry such as California specific requirements and transportation costs. This should be completed before the second compliance period. (KUSTIN18)

Comment: For the refining sector in particular, UCS is concerned that CARB has overestimated the likelihood of leakage risk, and this will result in subsidizing these carbon intensive facilities. We reiterate the need for a re-assessment of the leakage analysis to fully account for transportation costs and competitiveness of non-Californian products. We strongly support CARB's use of the simple barrel output based method (Appendix A, page 2) for the allocation of allowances for the refining sector as a whole in the first compliance period, and a move to full auctioning in the second and third compliance periods with rebates for investments in targeted carbon reduction technologies. (UCS8)

Comment: We are concerned about the changes in leakage assessment for certain categories of products with no explanation or supporting documentation. UCS feels that CARB is overestimating the likelihood of leakage risk, especially in the refining sector, and this will result in subsidizing (via free allocations) carbon-intensive industries. There are significant costs from the free allocation of valuable allowances. If auctioned as we recommend, these allowances could produce public monies rather than private assets and could be spent on lowering the costs of the cap-and-trade program. A reassessment of leakage risk is needed and should include transportation costs and the ability of non-Californian companies to compete with California producers, resulting in a more accurate assessment of actual risk. Imports of refined oil products are not competitive with domestically produced products because of transportation costs into California and the costs of adapting facilities to meet California's stringent fuel standards. Neither of these factors were analyzed when CARB assessed leakage risk for the refining sector. A reassessment of leakage risk categories should be done once this important research work is complete. Leakage risk analysis, especially for the refining sector, needs to fully consider the cost differential between imports and California production. This analysis should be completed before the start of the second compliance period. (UCS8)

Comment: The California refining industry is heavily exposed to leakage and should be classified as a High Energy Intensity Trade Exposed Industry, and not as a Moderately Trade Exposed Industry. Refined products can enter the state from refineries in other states and international sources. (TESORO3)

> **Response:** We will continue to monitor leakage risk of the petroleum refining sector in the context of an evolving global climate change policy framework. We agree that additional analysis could help further clarify the barriers to imports

created by transportation costs and California specifications for transportation fuels. We look forward to further dialogue with stakeholders on this issue.

Baseline Year

C-47. Comment: The proposed regulation uses the period 2008-2010 to determine sector quantity. However, ARB proposes to use 2008 year emissions to determine the sector quantity for other sectors including utilities. WSPA recommends that the 2008 year be used to determine sector quantity for all sectors in the cap and trade program. (WSPA4)

Response: We believe that the emissions data collected for the period 2008-2010 through our mandatory reporting program for greenhouse gases is accurate and representative for the refining sector. Therefore, we used these emissions data and product data from a similar period in calculating the sector-level benchmark in the first compliance period. We note that WSPA's current position on this issue has shifted, and that they originally proposed the use of 2006-2010 data for this purpose. We did not believe that we had accurate emissions data for all California refineries for the 2006 and 2007 data years, so we did not use these years in developing the benchmark for sector allocation.

However, for the EII allocation method of the first compliance period, we note that we will still consider 2006 and 2007 data from individual refiners, provided the data are representative, accurate and third-party verified.

Benchmark Stringency

C-48. Comment: We understand that ARB wishes to lead other jurisdictions to reduce greenhouse gases and that it also wants to reward companies for doing business in California in order to avoid leakage. However, rushing into an overly stringent program too early may work against both of these goals. It is widely understood that it takes time, often several years, to make physical and equipment changes in industrial operations in California due to permitting and public review processes, both of which will be required before any significant actual emission reductions can be achieved. Consequently, companies will not be able to make emission reductions quickly and will have to rely on offsets and allowances in the short term. The cap and trade program provides flexible options to minimize the cost. This is the most important strength of a market mechanism. The current benchmarks/hard start will result in significantly higher prices for both allowances and offsets because companies will need time to develop and implement less expensive emission reductions. These high prices will create further competitive disadvantages for California companies compared to their out-of-state competitors. This, in turn, will discourage other states and provinces from adopting a similar program, decreasing the likelihood of linking to them. The result is a growing negative impact on the California trade-exposed companies who remain in the state. A slow transition period that increases the benchmarks in the second and third compliance periods over the duration of the program would allow for both a reasonable economic transition and the development of a robust offset supply and cost-effective emission reduction investments. (CHEVRON4)

> **Response:** We disagree with the characterization of our initial benchmarks as a "hard start" that will raise allowance prices. The prices of allowances and offsets are set by the total aggregate supply of these instruments and the demand to emit. We carefully considered these factors in setting the aggregate cap (allowance budget) levels. The level of free allocation to an individual entity does not impact the price of these instruments. We believe our allocation approach is sufficient to minimize leakage from all emissions intensive and trade-exposed sectors.

C-49. (multiple comments)
Comment: Tesoro favors a benchmark that strongly considers baseline emissions for each refinery, and considers an indicator of energy efficiency, but tempers the results such that differences between refineries are reasonable relative to opportunities for improvement. We believe that the WSPA proposal met these objectives, but the stringency of the ARB benchmark has eliminated the effectiveness of the tempering factor. By reducing the stringency of the benchmark, the tempering could be restored and the allocation methodology would meet ARB's primary objective of setting a correct incentive for the initial period and allowing the program to start with minimal interruptions. (TESORO3)

Comment: One element that ARB has not accepted is the need to temper the influence of calculated refinery efficiency. Figure 2, of Appendix A to 2nd 15-day Cap-and-Trade Regulatory Text: Refinery Allocation Methodology illustrated a roughly 25 percent difference in allocation among members of the sector. As discussed in the following paragraph, this difference is 3 to 5 times too large. The WSPA methodology included a tempering factor, limited to zero or a positive number to reduce the impact of the raw calculated efficiency. But this tempering factor disappears, and likely become negative as applied by ARB in conjunction with the stringent treatment of the benchmark. As a minimum, Tesoro recommends that the Adjt factor as described in the following equation from section 95891 (d)(2)(A), be limited to a positive number:

Adjt=((Avg/EII Best)*Ft-1)/(1 Ft) (TESORO3)

> **Response:** We disagree. Our current approach already significantly reduces the spread between the best and the worst facilities relative to our initial simple barrel proposal. As shown in Appendix A to the second 15-say changes to the regulation, the best performers in the state have taken a reduced allocation to support additional allocation to the worst performers. We believe this level of "tempering" is sufficient to address concerns about intra-sector equity and the change to the current competitive playing field between California refineries.
>
> Board Resolution 11-32 directs the Executive Officer to continue to review information concerning the emissions intensity, trade exposure, and in-state

competition of industries in California and to recommend to the Board changes, if needed.

C-50. Comment: Amend the refinery benchmarking methodology to recognize new cuts in allowances. ConocoPhillips conditionally supports the proposal advanced by WSPA. ConocoPhillips offers only conditional support because the WSPA methodology, as proposed to ARB for the first compliance period, was constructed and negotiated by WSPA members before ARB's addition of the 10 percent cut. It assumed that the cut in free allowances would be in the range of ARB's stated 2012-2014 cap reduction of 3.7 percent. The much larger and additional 10 percent cut in allowances described makes the model operate in ranges that it was not designed for. This creates very large competitive differences of up to 20 percent or more in allowances provided to individual refineries. These misaligned competitive differences not only create severe competitive inequities between California refineries but also impose costs that are not placed on importing refineries as described above. Consequences unintended by ARB will most likely occur with the large disparities between in-state refiners and with international refineries created by this added burden. If CARB proceeds with the additional 10 percent cut in initial allowances, ARB and WSPA should again work cooperatively to further refine the EII-based methodology to address the new competitive concerns.

Further, ConocoPhillips strongly disagrees with ARB's statement in Appendix A that this methodology "should address concerns expressed by refinery stakeholders about transition risk and short-term competition issues between in-state refining facilities." The 20 percent difference in allowances shown in Figure 2 of Appendix A does not at all address short-term competition issues. Further, Figure 3 can be misleading in that it assumes that every California refinery will be able to secure the full 8 percent of allowable offsets during the first Compliance period that starts in only 15 months. (CONOCO3)

Response: We do not agree. We believe that benchmark stringency should reflect the emissions intensity of highly efficient, low-emitting facilities within each sector.

We strongly disagree with comments that characterize the approach to benchmark stringency as unexpected. The use of "90 percent of average" stringency for product-based emissions efficiency benchmark was initially indicated in the Staff Report released in October 2010. The following is a quote from page J-35 of that document:

"Staff believes benchmark stringency should reflect the emissions intensity of highly efficient, low-emitting facilities within each sector. Staff's current thinking is that the targeted level of stringency would be created by evaluating each industrial sector's emissions intensity during a historical base period and targeting the benchmark to allocate 90 percent of this level per unit product."

We developed this approach to benchmark stringency after careful analysis of California emissions intensity data and approaches used in other successful cap-and-trade programs. In selecting benchmark stringency, we are balancing the need to provide adequate transition assistance and minimize leakage with the necessity to meet AB 32's emission-reduction goals and prevent windfall profits through excessive free allocation.

Our current approach already significantly reduces the spread between the best and the worst facilities relative to our initial simple barrel proposal. As shown in Appendix A to the second 15-day changes to the regulation, the best performers in the state have taken a reduced allocation to support additional allocation to the worst performers. We believe this level of "tempering" is sufficient to address concerns about intra-sector equity and the change to the current competitive playing field between California refineries.

We believe sufficient offset supply will be available to meet the demand for offsets in the first compliance period. We are considering additional protocols to take advantage of low-cost greenhouse gas reductions from non-capped sources and increase offset supply in the second and third compliance periods.

Third-Party Cogeneration

C-51. (multiple comments)
Comment: ARB's current approach is discriminatory against refineries that rely on 3rd Party Cogeneration Operators for a portion of their power supply. There is currently no mechanism for these plants, or the Cogeneration Operators, to receive any quantity of free allowances. This is in contrast to refineries operating internal cogeneration units, who will receive allowances related to their baseline emissions including the cogeneration operation, and refineries purchasing power from utilities who will receive rate consideration associated with the utilities sale of free allowances at auction. We propose that emissions related to power provided by a Cogeneration Operator to a refinery be included in the refinery baseline emissions. One way to accomplish this would be a simple modification to the equation for baseline average annual GHG emissions. Modify section 95891 (d)(2)(A) as follows:

BEY=GHG+(SPurchased-SSold)*0.06244 ~~-eSold~~<u>(ePurchased Cogen-eSold)</u>*0.431

Where ePurchased Cogen is the power, in MWhr purchased by the refinery from the third party cogen plant.

Another possible solution would be to provide allowances directly to Cogeneration Operators for emissions related to power sales to refineries. As written, the regulation places refineries associated with third party cogeneration operators at a significant disadvantage and in fact discourages continued operation of the third party cogeneration plants. (TESORO3)

Comment: ARB has made no provision for allowances for power provided to the refining industry by industrial cogeneration plants. Emissions from these plants related to sales of steam and power to refineries should be included in baseline quantities and allowances. We recommend ARB revise the equation as follows:

To BE_Y, purchased electricity from third party cogens should be added as follows:

$$BEY = GHG + (S_{Purchased} - S_{Sold})*0.0663 + (E_{PurchasedCogen} - e_{Sold})*0.431$$

where:

"$E_{PurchasedCogen}$" is the annual arithmetic mean amount of electricity purchased from third party cogens by the refinery in MWh. This assumes that these cogens do not receive any allowances on their own. (WSPA4)

Response: We recognize the importance of indirect carbon costs. We aim to correctly incent the lowest greenhouse gas option among independently owned CHP, self-owned CHP, and separate production of heat and grid electricity.

We include adjustments for purchased heat and for heat and power sold in the refining benchmarking. We believe it is premature to add a uniform adjustment for power purchased at this time. This is because purchased power may not create an indirect carbon cost in all cases. It is ARB's goal to see a carbon price properly embedded in all purchased power. We believe a direct allocation to third-party cogeneration operators would potentially be counter to this goal because, given this free allocation, the operators may choose not to incorporate a carbon price into their rates.

If proper carbon pricing occurs in all purchased power, the compensation for these indirect carbon costs could be incorporated into the product benchmarks, if necessary, to help minimize leakage. We will revisit this issue once the California Public Utilities Commission Proceeding addressing utility costs and revenue issues associated with greenhouse gas emissions (R.11-03-012) concludes.

EII Methodology: Support

C-52. Comment: ARB's inclusion of the Solomon EII index within the allocation process is an important improvement in ARB's efforts to define an equitable allocation methodology. WSPA supports its inclusion in the allocation process because it rewards early action and energy efficiency without punishing California's more complex refining configurations, which are necessary to produce California's unique and cleaner fuels. Use of the EII is beneficial because the index recognizes the many products including many specialty chemicals and gases that are involved in the efficient transformation of crude oil into valuable products. Use of the EII is critical to the appropriate allocation of allowances in an emerging cap and trade program. If ARB proceeds with the additional 10 percent cut in allowances, ARB should agree to work with WSPA to further refine the

EII-based methodology and address new concerns that place California refiners at an unfair disadvantage. (WSPA4)

> **Response:** We thank you for your support. Moving forward, we prefer to focus the discussion on the refinery allocation approach for the second and third compliance periods. Board Resolution 11-32 directs the Executive Officer to continue to review information concerning the emissions intensity, trade exposure, and in-state competition of industries in California and to recommend to the Board changes, if needed. Board Resolution 11-32 also directs the Executive Officer to further develop the allowance allocation approach for the petroleum refining sector for the second and third compliance periods. This evaluation should include additional analysis of the Carbon Weighted Tonne approach.

C-53. Comment: The proposed regulations require that ARB choose the EII data from information submitted by refineries. This poses uncertainty as refiners are already in the process of developing their compliance strategy based on EII data already developed for their facilities. In addition, the proposed language also requires EII data for years that are not part of the biennial program. For example, while EII data for 2008 and 2010 data have been developed, data for 2009 and 2011 have not. The rule also requests EII data for years after the benchmark is set in the first compliance period. There is no basis for requiring this data after the EII benchmark is set. We recommend ARB use 2008-year EII data validated and reviewed by Solomon unless that year is not representative of normal facility operations. If data for 2008 are not representative of normal facility operations, then 2010 data can be used. Alternatively, companies may choose to submit 2009 EII information for use by ARB. (WSPA4)

> **Response:** WSPA proposed the use of the EII metric as a basis for allowance allocation in the first compliance period. This implies that this metric is a highly valuable in evaluating the energy efficiency of refinery operations. Therefore, we believe this is a metric ARB should monitor, and we will continue to collect EII data for years after the benchmark is set. We offered the flexibility to report odd-year EII data (e.g., 2009) for facilities that choose to do so. If no odd-year EII values are available for a facility, the facility may report the most recent even-year value.

C-54. Comment: In what is probably an inadvertent omission in the provision describing use of the EII index, ARB has not described a process for protecting EII information as competitively sensitive Confidential Business Information (CBI). ARB should develop provisions governing handling of facility-specific EII information so that such data are not used inappropriately or released outside of the agency. ARB should develop language to protect EII data as confidential business information. (WSPA4)

> **Response:** This concern does not require additional rule language. ARB has procedures in place for protecting data that are claimed as confidential. ARB's

regulations for confidential information can be found at Title 17, California Code of Regulations section 91000 et seq.

C-55. Comment: The methodology used for calculating the first compliance period refining sector allocation should match the methodology used for calculating individual petroleum refinery first compliance period allocations. Section 95870(d)(2)(A) addresses the first compliance period sector allocation using a “simple barrel" approach, but the individual petroleum refinery first compliance period allocations for facilities with a Solomon Energy Intensity Index (Ell) covered in Section 95891(d)(2) utilize an Ell weighting. In order to ensure consistency between the sector allocation and individual refinery allocations, Valero suggests that ARB apply the EII weighting approach for facilities with an Ell in establishing that portion of the refining sector allocation. As stated by ARB in the Summary of Proposed Modifications, the Ell is the most appropriate performance metric for complex facilities in the first compliance period. (VALERO3)

Response: We did not take the approach recommended by the commenter. It is unclear from the comment how we would “apply the EII weighting approach for facilities with an Ell in establishing that portion of the refining sector allocation.” Past methods of selecting a total sector amount have included selecting a sector-wide historical emission level, summing emission baselines from all facilities, or setting a sector benchmark and evaluating sector-wide production. We elect to use the benchmarking methodology.

By using the simple barrel benchmark to evaluate GHG intensity for the sector as a whole, the sector allocation is transparent and based on information that can generally be made publicly available. The total amount of allowances to the sector can increase or decrease automatically in response to future production levels of refinery products consistent with the product-based allocation approach for producers in other sectors. Likewise, the initial performance goal (benchmark stringency) for the sector is directly comparable to what is required for other industrial sectors. The sector allocation remains product based, creating an incentive to continue efficient production of primary refinery products in California and minimize emissions leakage.

EII Methodology: Oppose

C-56. (multiple comments)
Comment: In the first compliance period CARB proposes to use a simple barrel output based metric to allocate allowances for the refining sector overall. Coupled with a cap adjustment factor of two percent, the benchmark is estimated to limit the total allocation to the refinery sector. We strongly support a benchmark that reduces emissions below baseline to provide some level of incentive for emission reductions at the start, and the proposed 10 percent below sector-wide emissions from 2008-2010 (adjusted in future years by the level of the cap decline) represents a modest minimum reduction. The chosen benchmark however is fairly weak being solely based on California refinery

performance. According to U.S. Energy Information Administration data, California refineries emit up to 35 percent more CO_2 per barrel of oil refined than refineries in any other major U.S. refining region, (Karras, 2011) and significantly more than EU refineries (ICCT, 2011). Although we support the overall allocation to reduce the refinery sector allowances in the first compliance period, we remain very concerned over the proposed “two-pronged” method for distributing allowances among refineries, with a simple barrel approach for small refineries and a new *non-output* based approach for large, complex refineries in the sector. The individual allocation methodology for large refineries is problematic as it relies on grandfathering. This grandfathering level of free allowances is adjusted upwards for future increases and downwards for emissions with a tweak based on the Solomon Energy Intensity Index with the result that good and poor performers get about the same proportion of their emissions as free allocations. This methodology for large, complex refiners was originally proposed by WSPA. The narrow range in the distribution of allowances dilutes incentives for carbon reductions and minimizes the returns from investing in carbon reduction technologies. The impact of shifting the large refinery benchmark focus from carbon intensity of the final products to energy efficiency of the process rewards refineries that may utilize more modern equipment yet could have a much more carbon intensive overall process. Dampening the spread of refinery performance in the staff proposal compounds the potential resulting environmental and economic effects of this proposal. The net result is that overall GHG reductions in this sector are not sufficiently encouraged, missing an opportunity to encourage reductions in criteria and air toxic co-pollutants. Furthermore, as pointed out in earlier comments, the use of the Solomon EII index component of the grandfathering proposal is flawed since the rankings are based on energy rather than carbon efficiency. This can encourage use of high carbon feedstocks which would undermine the carbon reduction objectives of AB 32. In addition this index is an industry sponsored and funded benchmarking service which is proprietary. The black box rankings lack public accountability since they are both non-transparent and based on confidential information. Revert to the CARB original proposal for allowance allocation for all refineries instead of the two-pronged approach relying on primarily on grandfathering, updated for future emissions increases and decreases, as the large refinery GHG performance benchmark. Utilize a single benchmark which reflects national best practice carbon intensities. (KUSTIN18)

Comment: In the first compliance period, CARB proposes to use a simple barrel output-based metric to allocate allowances for the refining sector overall. UCS supports the use of an output-based metric which addresses leakage concerns and provides incentives for continued production of primary products in California. The adopted benchmark however is weak, being solely based on California refinery performance, which is much more carbon intensive than other U.S. regions (Karras, 2011). According to U.S. Energy Information Administration data, California refineries emit up to 35 percent more CO_2 per barrel of oil refined than refineries in any other major U.S. refining region (Karras, 2011). The benchmark adopted in the simple barrel output-based metric should be made much stronger to reflect national best practices and performance. CARB is proposing different methods for the distribution of the allowances among small and large complex refineries. The approach adopted for large refineries is very problematic as it relies on the Solomon Energy Intensity Index (EII) plus an adjustment factor used to reduce the spread of allowances between good and poor performers. This ‘tempering’ methodology for refineries originally proposed by the Western States Petroleum Association (WSPA) is troublesome as it deliberately narrows the distribution of allowances among refineries and so dilutes incentives for carbon reductions and minimizes the returns from investing in carbon reduction technologies. If facilities with both high and low emissions get virtually the same number of free allowances then there is little incentive for poor performers to invest in cost effective emission abatement technology. CARB argues that this adjustment is necessary to reduce the competiveness impacts of allowance allocation between in-state refineries (Appendix A, page 3), even though these economic impacts are a consequence of some refineries acting early to adopt more efficient technologies. The tempering adjustment is counter to the spirit and mandate in AB 32 to fully recognize early actions for emission reductions. In addition, as pointed out in earlier comments, the use of the Solomon EII index is flawed since the rankings are based on energy rather than carbon efficiency. Also, the proprietary methodology of the EII index results in a ‘black box’ ranking system which lacks public accountability, is non-transparent, and based on confidential information. We recommend that ARB adopt an output based benchmark that reflects national or worldwide emission intensity performance. Revert to the CARB original proposal for allowance allocation among all refineries and do not use the Solomon EII index as the large refinery GHG performance benchmark. Mitigate refinery distributional concerns (if deemed necessary) through financial aid specifically targeted to improve the carbon efficiency of poorer performers. (UCS8)

> **Response:** The total refinery sector allocation amount for the two years of the first compliance period will be set using the simple barrel benchmark. The value for this simple benchmark was updated from 0.0465 allowances/barrel of primary refinery products to 0.0462 allowances/barrel. We believe that this initial benchmark stringency is appropriate to minimize leakage. We will consider national data in the context of benchmark stringency as a robust national data set is developed by the United States Environmental Protection Agency’s greenhouse gas reporting program.
>
> For the first compliance period, simple refineries that do not have an EII value or those without a representative EII value as determined by the Executive Officer are allocated to using the “simple barrel” product benchmark proposed in the first 15-day changes to the regulation. A limit on the amount of allowances a facility can receive was imposed based on historical emission levels consistent with stakeholder comments. This approach will prevent a facility from receiving any excessive rewards due to free allocation under the simple barrel metric.
>
> Complex refiners’ first period allowances are allocated based on a methodology initially proposed by the Western States Petroleum Association. This approach allocates allowances based on the following factors: (1) historical emissions from for each refinery, (2) the Solomon Energy Intensity Index (EII) for each refinery, (3) an adjustment factor to reduce competitiveness impacts of allowance

allocation between in-state refineries, and (4) future emissions for each refinery. The Solomon EII is a complexity-adjusted measurement of refinery energy efficiency developed by Solomon Associates. Solomon Associates has been developing energy-efficiency benchmarking for energy-intensive industries for the past 29 years. They maintain an extensive database for refineries' energy consumption and process data covering over 70 percent of global refining capacity. We believe that the EII is the most appropriate performance metric for complex facilities in the first compliance period despite the fact that it is based on energy efficiency and not greenhouse gas efficiency. This metric is well understood by all complex facilities, and has been recognized under the U.S. EPA's ENERGY STAR Program. We believe that the allocation stringency correctly provides all facilities with the correct incentives to make greenhouse gas reductions. We do not agree that our approach supports poor performance.

The EII approach does significantly reduce the spread between the best and the worst facilities relative to our initial simple barrel proposal. As shown in Appendix A to the second 15-day changes to the regulation the best performers in the state have taken a reduced allocation to support additional allocation to the worst performers. We believe this level of "tempering" is appropriate to address short-term concerns about intra-sector equity and to create a gradual change to the current competitive playing field between California refineries (transition risk).

For the second and subsequent compliance periods, we will allocate to all refiners using the "Carbon Dioxide Weighted Tonne" approach. This metric is based on the refinery benchmarking conducted for the European Union's Emissions Trading Scheme and does not contain a "tempering" provision.

We recognize concerns about benchmark transparency associated with the EII values. However, other product benchmarks, such as the "simple barrel" approach that the commenter supports, also face transparency challenges because they are built on confidential information. EII values reported by each facility will be independently confirmed by third-party verifiers.

We do not agree that our approach creates an incentive to switch to lower-quality sources of crude. We agree that it is necessary to continue to review the allowance allocation to refineries as part of ongoing program review. Appendix A of the second 15-day changes to the regulation details the approach and analysis of the modified refinery allocation.

CWT Methodology

C-57. (multiple comments)
Comment: We recognize that a well-designed cap and trade program that is effectively linked with other programs around the world can be the most cost-effective mechanism that ARB has in its arsenal to achieve the goals of AB 32. We appreciate that the second 15-day package includes benchmarks for refining and oil and gas production

that are based on energy efficiency and reward early action, without penalizing complex refineries or California's unique oil and gas industry. We believe that by using complexity weighted approaches similar to those used in the European Union (EU), even better methods can be developed to promote refining efficiency. (CHEVRON4)

Comment: The proposed regulation cites the future use of a carbon-weighted index CWT. While WSPA agrees that some carbon-weighted index is appropriate, the use of the term CWT refers to a specific index used in Europe that may not be appropriate for use in the United States. ARB has indicated that they will review the various candidate carbon-weighted indexes in 2012. We recommend that ARB change the references to CWT with the term (CW) to allow the full evaluation of all appropriate carbon-weighted indexes for use in the second compliance period and thereafter. WSPA will work with ARB to identify an appropriate approach. (WSPA4)

Comment: Though discussed in general terms, the specific methodology, performance benchmark, and calculation details for the second compliance period allowance allocation were not placed in proposed regulatory language prior to this second 15-day packet, from which changes to the regulation cannot be accommodated prior to its finalization. Additionally, the effect of this approach could not be viewed in totality with the first compliance period allocation methodology presented during the first 15-day comment period. This new methodology is referred to as the Carbon Dioxide Weighted Tonne (CWT). The fact that the actual details of the CWT approach are not provided in this regulatory package, but are provided in the revised language for the MRR, only adds to the procedural obstacles in providing robust comments that can be acted upon by the CARB Board. CARB briefly outlines the rationale for choosing this CWT approach in Appendix A. One aspect of the proposal is to use a European Union benchmark as the performance standard for California refineries. This performance benchmark needs to be revised. WIRA agrees with Appendix A which states: [CARB] Staff plans to conduct additional technical work on the CWT approach in 2012 and will recommend any appropriate changes to the Board resulting from this analysis in a future regulatory package. As it is currently proposed this value will have a dramatic effect on WIRA, it will impact our members both directly and in terms of competitiveness relative to the state's larger, more complex refiners and therefore must be vetted in a more complete and robust public process. It is imperative that when this additional technical work is completed, that it be done in a timely manner such that all parties have sufficient understanding of its implications and have appropriate time to comment. When such additional technical work is initiated, WIRA will actively participate in the process. Even though the proposed CWT approach will not be in effect until 2015, for planning purposes, it is imperative that this work commence early in 2012. (WIRA4)

Comment: UCS is also concerned by the proposal to use the Carbon dioxide Weighted Tonne (CWT) measure in the second and third compliance periods. A report prepared for UCS in September 2011, provides empirical analysis that evaluates the factors driving the high emission intensity of California refineries. The key finding of the report is that California refineries work with much dirtier, lower-quality crude oils which require greater processing and produce greater carbon emissions and co-pollutants on average than refineries in other refining regions of the US. This research finding supports our concerns that CARB's proposal to use CWT will lead to subsidizing the refining of dirtier, lower-quality crudes and this will increase the costs of achieving the overall carbon reduction goals of AB 32. We recommend that CARB re-evaluate the use of the CWT and present documentation and analysis of how the CWT allowance allocations compare to the simpler output based methodology. In addition the adopted benchmarks should not support the use of dirtier lower quality crude feedstocks. UCS commends CARB for recognizing the need for this additional technical work and looks forward to participating and reviewing the analysis that will inform the future regulatory package mentioned in Appendix A, page 7. (UCS8)

Comment: In the second and third compliance period CARB is proposing to use an allocation methodology for individual refiners (small and large) that has been adopted in the European Union's Emission Trading Scheme (EU ETS), the EU carbon trading program. The proposal is to give refineries 0.0295 allowances per CWT they produce. The use of this benchmark is still in the implementation stages in the EU ETS, and it is slated to be introduced in 2013, at the start of the third phase of the EU carbon trading program. There is limited documentation available on the proposed benchmark which is derived from confidential non-transparent data. The underlying methodology is based on the proprietary Solomon Complexity Weighted Barrel (CWB) approach. The carbon efficiency basis of this metric is an improvement over the energy efficiency approach; however both are black box methodologies. From the limited documentation it is clear that more allowances are generated the higher the level of CWT, and CWT increases with greater process utilization; so if you increase the processing of your crude feedstock you get more allowances. These subsidies for greater processing of crudes will lower the cost of refining lower quality crude feedstocks. As is shown in Karras, 2011 the main reason why California refineries have much higher emissions intensity is because they use much lower quality crudes which require greater processing and produce greater carbon emissions as well as increased co-pollutants. California refineries use more "aggressive processing" than refineries in other parts of the US. These carbon intensive units, such as cokers and hydro-crackers, add to a refinery's "complexity" and also have the highest factors in the CWT system (e.g. a flexicoker has a CWT that is 16 times that for a regular distillation column). Some of the additional complexity used by California refineries may be necessary to meet the stringent fuel standards. However, it appears that most of the carbon intense aggressive processing in California refineries is driven by the use of lower quality crude oils. Figure 3 compares the use of processes for crude vs. product processing in California refineries versus those in other regions. Note the very heavy reliance of California refineries on crude stream coking and hydrocracking, two of the most energy intensive processes, while the product stream processing is similar across all regions. Thus the use of the CWT will subsidize and support the use of lower quality and more carbon intensive crudes. This is a serious concern which could lead to underinvestment in lower carbon emitting refining configurations, and conflicts with a key goal of AB 32. CARB should evaluate alternative benchmarks which do not subsidize the use of lower quality crude feedstocks. CARB should re-evaluate the use of the CWT and present documentation and analysis of how the CWT allowance allocations compare to the simpler output based methodology. We strongly support CARB's intention to undertake further technical analysis in the use of the CWT and look forward to participating in the review of the analysis that will inform the future regulatory package mentioned in Appendix A, page 7 to meet the goals of AB32. (KUSTIN18)

> **Response:** The petroleum-refining benchmark method we adopted for the second and third compliance period is the Carbon Dioxide Weighted Tonne metric initially developed for the European Union's Emission Trading Scheme. We recognize that this is a specific index. Currently, we believe this approach is appropriate for use in California, as specified in the regulation. However, we will continue to work with stakeholders to evaluate the robustness of this method prior to implementing it for the second compliance period. We do not believe this approach subsidizes the refining of dirtier, lower-quality crudes.

Other Allocation-Related Comments

C-58. Comment: ARB developed these [petroleum refinery] benchmarks and proposes to implement them using industry data that would be kept secret from the public. (CBE4)

> **Response:** By using the simple-barrel metric to evaluate GHG intensity for the sector as a whole, the sector allocation is transparent and based on information that can generally be made publicly available. The total amount of allowances to the sector can increase or decrease automatically in response to future production levels of refinery products consistent with the product-based allocation approach for producers in other sectors. Likewise, the initial performance goal (benchmark stringency) for the sector is directly comparable to what is required for other industrial sectors.
>
> We recognize concerns about benchmark transparency associated with the EII values. However, other product benchmarks, including the simple-barrel approach, also face transparency challenges because they are built on confidential information. EII values reported by each facility will be independently confirmed by third-party verifiers. Because we cannot share data submitted confidentially, we cannot publish the full benchmarking calculations. We believe we have provided sufficient detail regarding our benchmarking approach in the Staff Report, Appendix B to the first 15-day notice, Appendix A to the second 15-day notice, and through continued dialogue with stakeholders, to provide an understanding of the results of our analysis.

C-59. Comment: Elements of ARB's proposal (cap–and–trade instead of direct control, free allowances, and emission benchmarks) must be evaluated together for two reasons. First, ARB's cap, allowances, and benchmarks interact via mathematical equations (section 95891). Second, ARB's rationales for proposing cap-and-trade and free emission allowances rely on the same assertion. ARB asserts that both of these elements of its proposal improve climate protection because controlling industrial emissions here may have the negative effect of increasing emissions elsewhere so that total emissions are not reduced and may increase. ARB claims this could happen because companies could shift their production outside California instead of cleaning up, and that shift—according to ARB's assertion—increases emissions as much or more elsewhere. ARB calls this "emissions leakage."

Thus, ARB assigns free allowances to 100 percent of refinery emissions because ARB estimates a 100 percent risk that making refineries curb emissions will cause refinery emissions elsewhere to increase as much as or more than those emissions are reduced in California. (CBE4)

> **Response:** We do not "assign free allowances to 100 percent of refinery emissions." We are allocating allowances to the industrial sector for *two* purposes: (1) to provide transition assistance, and (2) to prevent leakage. Transition assistance provides free allocation to the industrial sector at the outset of the program to avoid sudden or undue short-term economic impacts and to promote a transition to a low-carbon economy. This transition assistance will decline as covered entities gradually adjust to the carbon price and adopt energy-and carbon-saving strategies.
>
> Free allocations will decline over time based on two main factors. One is the "cap decline" or "cap adjustment" factor. This ensures that we will reduce emissions to meet the 2020 goal. The cap declines at two percent each year for the first compliance period, and then at three percent a year from 2015 through 2020.
>
> The second factor is based on the risk of emissions leakage. We have conducted an extensive analysis of leakage risk with a peer-reviewed methodology used in existing cap-and-trade programs. This methodology combines two considerations—trade exposure and the degree to which greenhouse gas emissions influence the cost of the end product. The methodology is described in greater detail in the *Staff Report: Initial Statement of Reasons* and its Appendix K.
>
> Sectors that have high leakage risk will continue to receive a high percentage of allowances for free through 2020. Sectors with medium or low leakage risk will see reductions in their free allocations beginning with the second compliance period in 2015. These percentages of free allowances are detailed in the regulation. Per Board direction in Resolutions 10-42 and 11-32, we are committed to revisit the leakage analysis before 2015, and to adjust leakage risk as necessary to reflect the results of the revisited analysis. Petroleum refining is classified as medium leakage risk. The assistance factor for this category is 100 percent for the years 2013 and 2014, 75 percent for the period 2015–2017, and 50 percent for the period 2018–2020.

The total decline to the refining allocation created by the cap adjustment factor and the assistance factor is shown in the following table.

Year	2013	2014	2015	2016	2017	2018	2019	2020
Cap Adjustment Factor (From Table 9-2)	98.1%	96.3%	94.4%	92.5%	90.7%	88.8%	86.9%	85.1%
Petroleum Refining Assistance Factor (from Table 8-1)	100.0%	100.0%	75.0%	75.0%	75.0%	50.0%	50.0%	50.0%
Combined Adjustment to Refining Allocation	**98.1%**	**96.3%**	**70.8%**	**69.4%**	**68.0%**	**44.4%**	**43.5%**	**42.6%**

C-60. Comment: ARB's position that its proposal to allow continuing or increasing refinery emissions will not disparately impact low income communities of color because other existing requirements prohibit increasing GHG co-pollutant emissions is disingenuous and wrong. California refinery GHG co-pollutant emissions already cause disparately high, health-threatening exposures to particulate matter in nearby low-income communities of color. ARB allows this disparate impact. It allows extremely high refinery emissions on average. By further allowing these high emissions to continue, let alone increase, ARB's proposal would worsen this disparate impact. (CBE4)

Response: We disagree. We evaluated the potential for localized increases in co-pollutant emissions in affected communities due to a cap-and-trade program to the best of our ability during the regulatory development process. The findings of this analysis can be found in the *Staff Report: Initial Statement of Reasons* and its Appendix P: Co-Pollutant Emissions Assessment. Since the distribution of changes in co-pollutant emissions resulting from the cap-and-trade program are dependent on how individual facilities choose to comply with the program, we evaluated how co-pollutant emissions could change in three hypothetical scenarios within four environmental justice communities—Wilmington, Oildale/Bakersfield, Richmond, and Apple Valley/Oro Grande. Under the three hypothetical scenarios, we found that co-pollutant emissions could, in the absence of district permits and existing controls, increase or decrease a very small amount. However, most compliance approaches are expected to result in a reduction in co-pollutants through increased efficiency and decreased combustion of fossil fuel. It is important to note that the mere presence of a cap-and-trade program for greenhouse gas emissions will not weaken or reduce facility specific requirements or permits for co-pollutants. All facilities will continue to be subject to existing local ordinances and rules. A brief discussion of key existing air quality laws that minimize potential adverse impacts is presented below.

The federal Clean Air Act (CAA) of 1970, as amended in 1977 and 1990 (42 USC section 7506(c)), establishes National Ambient Air Quality Standards (NAAQS) for air pollutants that pose a threat to human health and welfare. California has adopted more stringent air quality standards for most of the federal criteria pollutants under the California Clean Air Act of 1988. Similar to the federal standards, the California standards have been designed to protect the health of the most sensitive persons with a margin of safety.

New Source Review (NSR) is a title applied to programs regulating the new construction of, and/or modifications to, industrial sources that emit, or will emit, air pollutants. NSR requirements under State law are codified in Division 26 of the California Health and Safety Code. Specific to NSR, each local air district is to include in its attainment plan a stationary source control program designed to achieve no net increase in emissions of nonattainment pollutants or their precursors for all new or modified sources that exceed particular emission thresholds. Each of the 35 air districts in California has its own NSR program and issues permits to construct and operate. The permit requirements are dependent on the California AAQS or NAAQS designation (attainment, nonattainment, and unclassifiable areas), and the amount and type of pollutants that the source will emit. In addition, most new and modified stationary sources are required to use Best Available Control Technology. Furthermore, all the air districts have either a policy or regulation that addresses toxic air pollutants for new and modified sources.

The California Environmental Quality Act (CEQA) review of local projects may identify and require mitigation for mobile and other emission sources. CEQA requires that, where a project will have significant impacts, the lead agencies (in this context, cities, counties, and air districts) must consider alternatives (including, where appropriate, alternative locations that would have fewer impacts) and require feasible mitigation to reduce those impacts to less than significant levels. Mitigation for a given project could include additional pollution control technologies, off-site measures, and mobile source mitigation that would reduce cumulative pollution in the area affected. Further analysis of what may be appropriate for specific, future energy-related projects must be analyzed in response to a specific proposal.

Facilities whose toxic air contaminant emissions and risk potential exceed a certain threshold must prepare a Health Risk Assessment under the “Hot Spots” Information and Assessment Act. This and other regulations will continue to result in significant reductions in co-pollutant emissions, exposure, and health-based risk.

Moreover, through the Energy Efficiency and Co-benefits Assessment Regulation for Large Stationary Sources, we are currently collecting information on opportunities for further GHG and co-pollutant emission reductions. We are scheduled to receive these data by the end of 2011. We will initiate a process to ensure that large industrial sources subject to the regulation be required to take cost-effective actions identified under those audits. The audit results, due to ARB by the end of 2011, will inform the development of regulatory requirements that staff intends to propose to the Board in 2012. We plan to initiate a separate public process in fall 2011 to discuss metrics and actions to implement this commitment.

Although we anticipate that co-pollutant emissions would decrease, ARB is committed to monitoring the implementation of regulation to identify and to address any situations where the program has caused an increase in criteria air pollutant or toxic emissions. In Resolution 11-32, the Board approved an Adaptive Management Plan to monitor and respond to unanticipated adverse localized air quality impacts of the proposed cap-and-trade program. Under this plan, at least once each compliance period, we would use information collected through the mandatory reporting regulation, the proposed cap-and-trade regulation, the industrial efficiency audit, and other sources of information to evaluate how individual facilities are complying with the regulation. If any adverse impacts are identified we would, if feasible, modify the program to lessen the impacts.

A separate but related concern is that a greenhouse gas emission trading program could increase existing inequities related to the burden of air pollution exposure; that is, low-income and minority communities would bear a disproportionate share of the impact of unforeseen increases in air pollution and/or would experience less of the benefits from a cap-and-trade program. Data and research clearly indicate that a disproportionate share of facilities with high GHG emissions are located in low-income communities with a high percentage of minorities, and the annual co-pollutant emissions burden from large GHG emitting facilities is larger for minorities. However, this is entirely different than finding that facilities located in minority neighborhoods are more likely to buy allowances or offsets instead of reducing emissions on site, and are therefore going to incur less benefit than other communities. In fact, numerous studies have evaluated the potential for inequitable impacts from emissions trading programs on minority neighborhoods, racial and ethnic groups, and general community demographics, and found that trading did not have a disproportionate impact. As noted by the Market Advisory Committee, “U.S. Environmental Protection Agency staff analysis found that under the SO_2 emission trading program, the largest reductions occurred in areas with the highest emission levels. This finding was true both regionally and at individual plants.” Thus, it is possible that the areas with highest emissions could observe disproportionate benefits from a cap-and-trade program.

The most effective way to reduce the impacts of co-pollution emissions in low-come and disadvantaged communities is to implement programs that target reductions in co-pollutant emissions directly. While a GHG focused program would likely reduce co-pollutant emissions along with GHG emissions, it is not the most effective mechanism for decreasing exposure to co-pollutants.

C-61. Comment: Figure 1 shows average production-weighted GHG emissions (lb/barrel crude) in California, other major U.S. refining regions, and Europe. The California and other U.S. emissions are verified based on publicly reported data. The European emissions are reported as verified by the EU. Statewide, average 2004–2008 California refinery emission intensity exceeds that of any other major U.S. refining region by 19–36 percent and exceeds the average 2005–2008 emission intensity of European refineries by 89–120 percent.

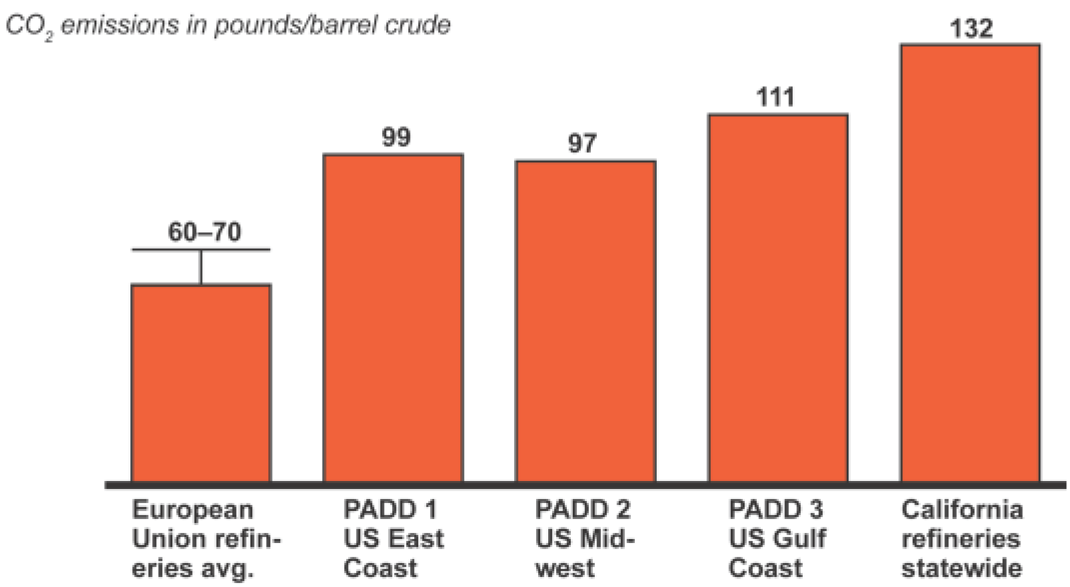


Figure 1. Average refinery emissions intensity by region. PADD: Petroleum Administration Defense District. California and U.S. emissions, 2004–2008, from fuels consumed in refineries including third-party hydrogen production; data given in Attachment 1 to these comments. European Union emissions, 2005–2008, from average of CITL and CONCAWE "verified" emissions and crude volume refined in countries included for emissions based on 85–100 percent of crude charge capacities from Oil & Gas Journal. The 60–70 lb/b range shown for Europe reflects this 85–100 percent range in capacity utilization. This bounding range is used because refinery capacity utilization was not reported for Europe.

Causal analysis further confirms California's extreme-high average refinery emissions. The quality of crude oil refined is the major driver of differences in average refinery emission intensity nationwide and in California. This is because making gasoline, diesel, and jet fuel from denser, higher sulfur crude requires putting more of the crude barrel through aggressive processing that takes more energy and burns more fuel for this energy, thus boosting refinery energy and emission intensities. The impact on energy intensity is illustrated in Figure 2. Crude feed density and sulfur content can explain 90–96 percent of increasing CO_2 emissions from the lowest to highest emitting refineries across the U.S. and California, and predict the extreme-high 2004–

2009 average emission intensity of California refineries within 1 percent.

Figure 2. Refinery energy intensity *(EI)* predicted by crude feed density and sulfur

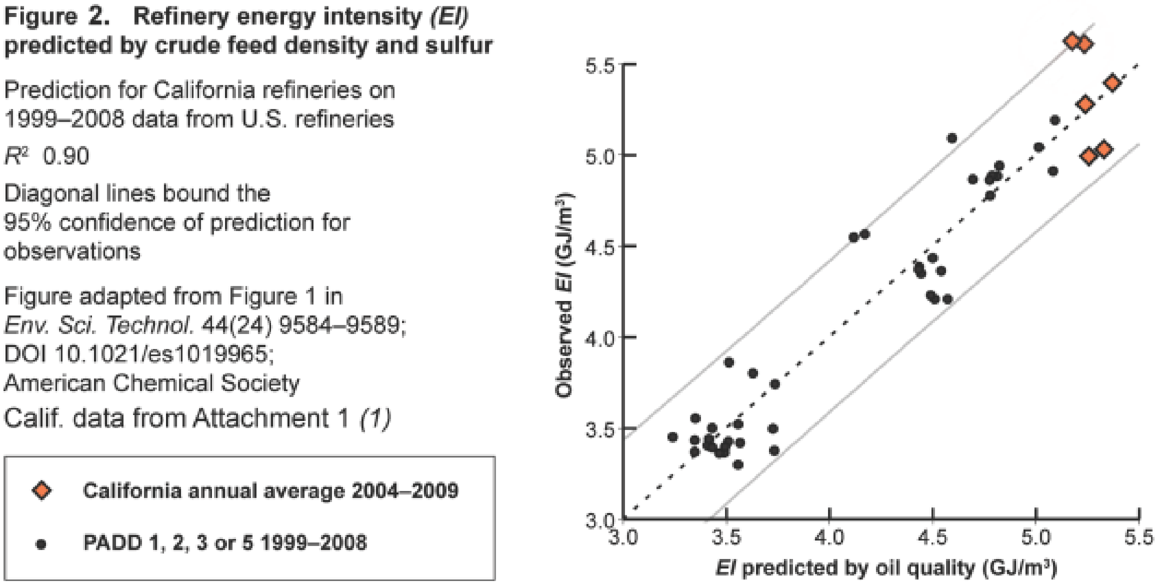
Prediction for California refineries on 1999–2008 data from U.S. refineries

R^2 0.90

Diagonal lines bound the 95% confidence of prediction for observations

Figure adapted from Figure 1 in *Env. Sci. Technol.* 44(24) 9584–9589; DOI 10.1021/es1019965; American Chemical Society

Calif. data from Attachment 1 *(1)*



ARB now proposes “benchmarks” designed by oil industry consultants to assign higher emission expectations to more “complex” refineries with more capacity to further process the oils from their initial crude distillation. ARB’s refinery “complexity” benchmarks are a polluter’s dream. They are designed to reward the refining practice that boosts emissions the most. They artificially make the resultant high refinery emission intensity look like “good” environmental performance. They keep data secret so that refineries can hide their polluting practices from the public.

Benchmarking emissions against refinery complexity predicts very high average emissions for California refining based on its very high primary processing equivalent capacity (Figure 3).

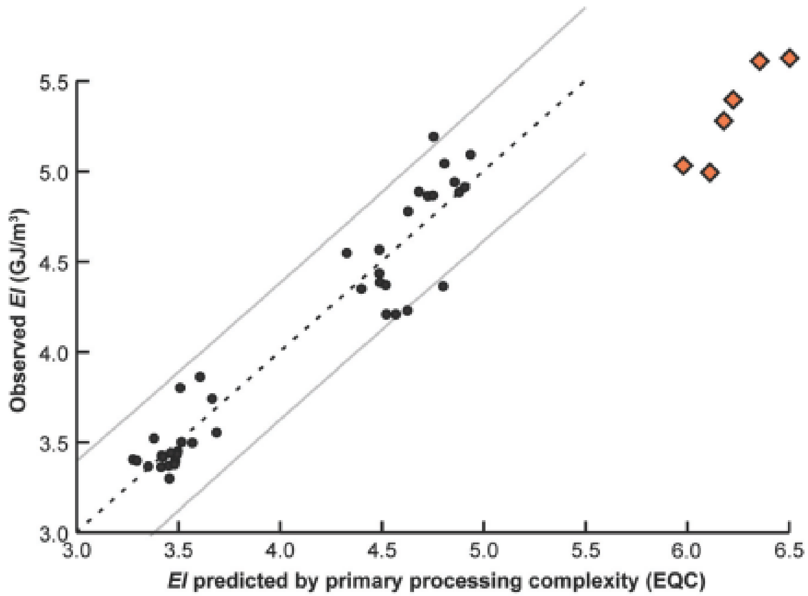


Figure 3. Energy intensity *(EI)* predicted by primary processing equivalent capacity

Prediction for Calif. on 1999–2008 data from U.S.

R^2 0.92

Diagonal lines bound 95% confidence of prediction for observations

Figure adapted from Union of Concerned Scientists *(3)*; data from Attachment 1 *(1)*.

◆ **California annual average 2004–2009**

● **PADD 1, 2, 3 or 5 1999–2008**

This prediction (Figure 3) makes sense because primary processing capacity enables refining dirtier crude, which is the main driver of refinery emission intensity as discussed above. Further, the over-prediction of California refinery emissions by this complexity benchmark (California data are shifted to the right in Figure 3 as compared with Figure 2) makes sense because California refineries use much more gas oil hydrotreating to pretreat catalytic cracking feeds than other regions on average. By treating more of the oil before cat-cracking (and reforming) it in this way, California refineries could reduce the energy and emission intensities of those other individual processes marginally. That would cause their total refinery emissions to be slightly lower than predicted by nationwide refinery complexity data (Figure 3) even though their emissions stay right in line with those predicted by their more energy-intensive, lower quality crude feeds (Figure 2). The result is that ARB's benchmark, which compares actual refinery emissions only to the diagonal lines in Figure 3 that it predicts based on complexity, and is blind to whether actual emissions are higher or lower than those of other refineries in this chart, predicts California refinery emissions that are even higher than their extreme-high actual levels.

The trick in ARB's proposal is that it turns this limited and partly inaccurate complexity-based prediction into a performance expectation that assigns more emissions allowances to more complex refineries. ARB's benchmark could thereby tell ARB to expect even higher emissions than those observed in California, and artificially assign "better than expected" emissions performance to the highest average refinery emission intensity in the country.

Worse, because increasing primary processing capacity enables refining lower quality crude, by awarding more free emission allowances to more complex refineries with expanded capacity to process this inherently dirtier crude, ARB would encourage the very same refining practice that increases refinery emissions the most.

Our summary of crude quality and processing intensity impacts on refinery energy and emission intensities here is based on peer reviewed work that accounted for and verified the relationships of these factors and also other refinery processing, product slates, and fuels burned for energy in refineries, using data from operating plants across 97 percent of the U.S. industry, and extended the same methods to California-specific data. ARB's erroneous claim that this work does not account for impacts of processing capacity and product slates (Supp. FED RTC at 106-67,106-68) should be corrected for the record, and further suggests a key weakness in the agency. It suggests that ARB misunderstands the major cause of the extremely poor emission performance it has allowed across the highest-emitting industry in California. ARB's weakness will be compounded if critical data for assessing refinery emissions performance are kept secret. (CBE4)

> **Response:** We believe that complexity-adjusted allocation methods are neutral to crude quality. That is, they neither excessively penalize nor reward refineries sourcing poorer quality crude. We do not believe these methods create an incentive to switch to poorer quality crudes. The phase-out of free allocation and switch to auctioning as the primary method for allocation to the refining sector by the third compliance period will penalize facilities with more emission-intensive processing, including more emissions-intensive processing due to crude quality.
>
> During the first two years of the cap-and-trade program, the complex refineries will receive their allowance allocation according to an allocation method based on the Solomon EII, which is a complexity-adjusted measurement of refinery energy efficiency developed by Solomon Associates. Solomon Associates has been developing energy-efficiency benchmarking relied upon by the industry for the past 30 years. They maintain an extensive database of more than 500 refineries' energy consumption and process data, covering over 85 percent of global refining capacity, which is used to develop the EII values. The Solomon EII is the industry standard for comparing energy efficiency across refineries globally. California refineries that have a Solomon EII value represent over 90 percent of refining capacity in the State.
>
> Under the Solomon EII benchmark, the facility with the best (most efficient) EII will receive the greatest portion of their historical emissions baseline. Less-efficient facilities will receive smaller portions of their individual historical emissions baseline. This benchmark methodology, along with the prospect of a decreasing percentage of free allocation in the second and third compliance period, will incentivize refineries to decrease their GHG emissions.
>
> After the first compliance period, all refineries will receive a reduced level of free allocation. This reduction in free allocation is due to the cap adjustment factor and the assistance factor. The refinery benchmark methodology will also change to the Carbon Dioxide Weighted Tonne (CWT) metric initially developed for the European Union's Emission Trading Scheme. Extensive work has been conducted using a robust data set of European refineries to create the CWT

approach. This metric is preferable to the EII approach proposed in the first compliance period because it is based on greenhouse gas intensity, adjusts to recognize refinery complexity, and can provide equity between all possible ownership structures for hydrogen production, electricity, and heat production, and coke-calcining facilities.

The method also is not dependent on a proprietary index and, therefore, is somewhat more transparent. However, the information necessary to calculate the metric is still generally confidential business information.

Some stakeholders noted a concern that the use of the EII metric only considers energy efficiency and not greenhouse gas efficiency. A move to the CWT allocation methodology in the second compliance period addresses this concern. Staff plans to conduct additional technical work on the CWT approach in 2012 and will recommend any appropriate changes to the Board resulting from this analysis in a future regulatory package.

In its response (Supp. FED RTC at 106-67,106-68), ARB staff did not assert that the peer-reviewed work referenced by the commenter "does not account for impacts of processing capacity and product slates." ARB replied that "California refineries are far more complex and create higher percentages of highly refined products than refineries in the rest of the nation." This point is borne out by publically available statistics, and it is one of the reasons that California refineries emit more GHG emissions per barrel of crude charged. Furthermore, in its response, ARB staff said: "The commenter's premise—that heavier, higher sulfur crudes require more energy to refine, and therefore result in higher GHG emissions per unit of output—is valid." We agree on that point.

C-62. Comment: ARB's proposals come at the worst time. California refineries are beginning a major crude supply switch now. Only about 25–30 percent of their crude feed will be from existing sources of California production by 2020. This means they will retool for different "new" crude oils—and lower quality crude is cheaper. They will target the highest-profit balance between cheaper feedstock, and the costs and liabilities of adding capacity for and refining dirtier crude. But ARB would protect them from liability for their pollution with emission allowances that are free now and cheaper than the profits from dirtier crude later, and subsidize retooling for lower quality oil with benchmarks that give more allowances to refineries with more capacity to process it. ARB's cap–and–trade scheme, free allowances and benchmarks would thereby allow, support, and ensure a switch to refining "dirtier" oil. That oil could be much dirtier (Figure 4).

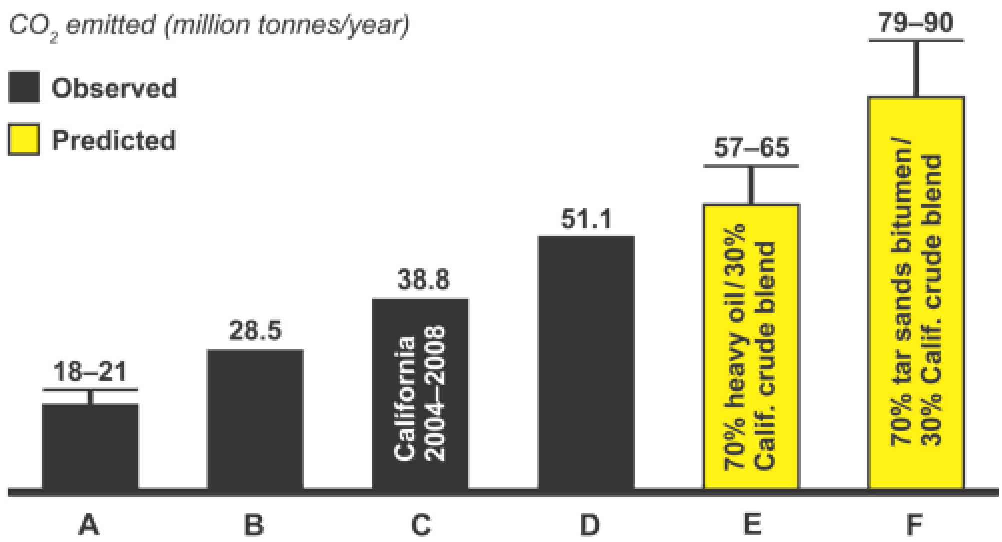


Figure 4. Refinery mass emissions from California's current production rate at observed and predicted potential refinery emission intensities. All emissions shown for the California statewide average crude input observed 2004–2009 (647.44 MM barrels/yr).

A: European Union refineries average emission intensity observed 2005–2008
B: U.S. Midwest PADD 2 refineries average emission intensity observed 2004–2008
C: California statewide refineries average emission intensity observed 2004–2008
D: Emission intensity based on 2008 data reported by Shell Martinez refinery
E: 95 percent confidence of prediction for 70 percent heavy oil/30 percent California-sourced crude feed
F: 95 percent confidence of prediction for 70 percent natural bitumen/30 percent Calif.-sourced crude feed

Emissions in the E–F range are foreseeable if current, declining California production is replaced by low-quality crude. Predictions based on the average density and sulfur content of heavy oil, natural bitumen and 2004–2009 California crude production by the method from Karras 2010.

Recent work found a switch to dirtier crude could double or triple refinery emissions. Figure 4 shows some of that potential has been realized, and applies the prediction method from this peer reviewed work to the California crude switch. Because crude quality is the major driver of refinery emission intensity, the emissions increment will depend on how far refiners shift the 70–75 percent of their feed that will no longer be from existing California sources of production toward the densest, dirtiest oils. Replacing 70 percent of their crude feed with the average "heavy oil" as defined by USGS could increase statewide refinery emissions by 18–26 million tonnes/year (Column E). Though huge, this emission intensity increment is already approached by least one California refinery (Column D) and represents the low end of the potential to pollute.

Replacing that same 70 percent of California refinery crude feed with the average-quality natural bitumen could boost emissions by 40–51 million tonnes/year (Column F). This worst-case scenario is plausible to the extent that ARB finds it cannot monitor and control production activities in other nations, especially if the planned Alberta–British Colombia tar sands pipeline and port expansions are built. The dirty oil switch would most likely include some combination of heavy oil and tar sands inputs—which would emit somewhere between the low and high cases shown by columns E and F in Figure 4.

Other existing policies will not prevent this crude quality-driven emissions increase. This is starkly evident in the extreme-high average refinery crude feed density and emissions that these policies allow on ARB's watch. But ARB's claim that existing controls on "criteria" pollutants will prevent a crude quality-driven emissions increase is both wrong and specious. By using up the limited remaining capacity of emissions capture technology, the crude switch that ARB would allow would foreclose otherwise available emission reductions.

Thus, ARB's proposal is likely to increase California refinery emissions by some 18–50 million tonnes/year. Even the low end of this estimate could overwhelm other planned efforts here and—if copied elsewhere—impede or foreclose the total cut in emissions from all sources that is needed to avoid severe climate disruption. Since burning more fuel to refine low quality oil emits toxic and smog-forming combustion products along with CO_2, it would worsen existing disparately high exposures to harmful refinery GHG-co-pollutants in low income communities of color. The sunk costs invested in refinery capacity tooled for dirtier crude would commit us to those emission increments for decades. Impacts on climate from those decades of added CO_2 emissions would be cumulative over generations. Therefore, ARB's proposal would result in significant and disparate impacts on environmental health in low income communities of color, and significant cumulative and irreversible impacts on future generations' ability to avert catastrophic climate disruption. (CBE4)

> **Response:** We do not agree that our approach creates an incentive to switch to lower quality sources of crude, or that this regulation comes at a bad time. We believe that this regulation will incentivize refineries to reduce GHG emissions through the imposition of a price on those emissions. Furthermore, the high-carbon-intensity crude oil provision in the Low Carbon Fuel Standard regulation penalizes additional processing of heavier crudes that take more energy to extract (e.g., bitumen mining, thermally enhanced oil recovery techniques).
>
> Only during the first two years of the program will some refineries receive most of the allowances they will require for compliance with the program. By the third year of the program, refineries will be required to purchase over one quarter of required compliance instruments, and by 2018 will be required to purchase over half of the compliance instruments required for program compliance.

The cap-and-trade program is not intended to prohibit any and all refining expansion. The goal of the program is to ensure that refining facilities incorporate carbon costs associated with future emissions when planning capital investments. After weighing these costs, some facilities may still choose to make these investments.

We believe that existing programs for control of criteria pollutants will prevent a pollutant emissions increase driven by crude feed quality criteria.

C-63. Comment: Newly disclosed facts prove that ARB's basis for exempting California oil refineries from emissions control measures cannot possibly be valid. As described above, ARB's rationales for proposing cap-and-trade and free emission allowances rely on the assertion that controlling industrial emissions here could shut down production here and increase emissions elsewhere so that total emissions are not reduced. ARB maintains this "emissions leakage" assertion at the same time that it accepts the higher emission intensity of California refineries, the crude quality-driven cause of higher refinery emissions here, and the ongoing California refinery crude supply switch documented above as true. ARB ignores what these newly disclosed facts mean about its comparison of climate protection alternatives.

California refineries could achieve the lower emission rates achieved on average in other major U.S. refining regions by switching to crude feed of the quality refined across these other major U.S. refining regions today (see figures 1–4). California refineries must adjust to a changing crude supply anyway. They can be required to adjust to a less-dirty crude supply instead of an inherently dirtier one. The only reason they might not (and those elsewhere might "catch up" to their pollution rate) would be if refineries are allowed to pollute in violation of environmental rights, and that policy would clearly be improper, so it would be an invalid rationale.

Thus, other major U.S. refining regions achieve lower emission rates by doing what can be done here while continuing production, in direct contradiction to ARB's claim that refiners here would shut down production instead of cleaning up. Together with the product transport and marketing logistics that drive refineries to be near their markets rather than their crude supplies in general—and insulate California refiners from competitors who would have to ship across the Rocky Mountains or the Pacific in particular—this proof that other refineries continue production while achieving lower emission rates debunks ARB's emissions leakage claim.

Moreover, even if California refineries reduced emissions by reducing production and this caused refineries elsewhere to increase production by the same amount to supply constant demand here, the "reduction in GHG emissions within the state that is offset by an increase in GHG emissions outside the state" asserted by ARB's emissions leakage claim is mathematically impossible. California refining emits more GHG per barrel: shifting its production to other regions would reduce total emissions. Based on the data in Figure 1, a barrel-for-barrel production shift from California to the Midwest, or to Europe, cuts bi-regional refinery emissions by 26 percent, or 47 percent, respectively.

Newly disclosed facts that ARB accepts as accurate prove ARB's assertion of refinery emissions leakage risk is false. ARB's decisions to apply its cap-and-trade scheme to refineries and to give refineries free emission allowances instead of reducing their emissions more effectively through direct control measures rely upon this false emissions leakage assertion. Therefore, ARB's decisions to develop and propose a cap-and-trade scheme instead of direct industrial emissions control measures and to give refineries free emissions allowances instead of controlling their emissions are based on factual findings that are false and are invalid. (CBE4)

> **Response:** ARB has never maintained that emissions-control measures should not be implemented alongside the cap-and-trade regulation. In fact, as part of ARB's AB 32 programs, we are requiring large industrial facilities, including petroleum refineries, to conduct an energy efficiency assessment of sources of greenhouse gases to determine the potential emissions-reduction opportunities, including those for criteria pollutants and toxic air contaminants. ARB will use results from the *Regulation for Energy Efficiency and Co-Benefits Assessment of Large Industrial Facilities* audit to determine if certain emissions sources within a facility can make cost-effective reductions of greenhouse gas emissions that also provide reductions in other criteria or toxic pollutants. Where this is the case, rule provisions or permit conditions would be considered to ensure the best combination of pollution reductions.
>
> Our stringent cap-and-trade program, which requires petroleum refineries to buy over half of the compliance instruments required for program compliance within six years of the start of the program, will incentivize cost-effective GHG emissions reductions at these refineries. Further, the program will ensure that the State reaches the AB 32 goal of cutting our emissions to 1990 GHG levels by the year 2020.
>
> The commenter asserts that it is mathematically impossible for out-of-state refineries to increase GHG emissions equal to an emissions reduction from California refineries. However, AB 32 requires that ARB minimize leakage, defined as a reduction in GHG emissions in California offset by an emissions increase outside the State, in the design of the program. In addition, the commenter's assertion relies on the assumption that out-of-state refineries—most with less stringent GHG and co-pollutant regulations than California's—would not utilize the crude that California refineries currently process. We believe that this is an unlikely scenario, as oil producers would likely find refineries to take the crude currently refined in California if GHG constraints incentivized crude switching or closure of the California facilities.

D. AUCTION

Unsold Allowances

D-1. Comment: We ask that ARB direct at least half of all unsold allowances when an auction clears at the reserve price to the Allowance Price Containment Reserve (Reserve). In place of the Reserve, staff is now proposing to make these allowances available at subsequent auctions. We support staff's proposal to hold back any unsold allowances from auction until two consecutive auctions clear above the reserve price to guard against the risk of consistent over-allocation. By directing *all* unsold allowances back into the auction holding account, however, ARB has left the program without a provision to backfill the Reserve. We are concerned this could expose the program to undue political pressure should market conditions lead to the Reserve being accessed. With no other mechanism built-in to resupply the Reserve, stop-gap proposals to provide additional cost containment will in all likelihood seriously undermine the integrity of the cap. We are also not persuaded by ARB's rationale for making the proposed change. ARB cites to stakeholder concerns that directing unsold allowances to the Reserve would unnecessarily reduce the supply of allowances to the market. In our view, the very fact that allowances are remaining unsold at auction provides clear indication that the market is *already* oversupplied. Entities can also readily guard against the risk of future allowance shortages through the program's unlimited banking provisions. Accordingly, we maintain that the most appropriate use of unsold allowances is to backfill the Reserve, and ask that ARB direct at least half of unsold allowances to that end. (KUSTIN19)

> **Response:** We never intended sending unsold allowances to the reserve to be a way of backfilling the reserve. The reserve would need to be replenished if there were a chronic shortage of allowances in the market. Instead, sending unsold allowances to the reserve was a method of removing an initial oversupply of allowances. However, we became convinced that an initial oversupply could be followed by a market that is too short of allowances. For example, emissions may be much lower than the cap in the first few years of the program if the current economic recession continues or if our forecasts of emissions are wrong. This situation would lead to an initial oversupply. However, we believe that the cap set in 2020 represents a significant reduction in emissions. In addition, if the direct measures fail to achieve their expected emissions reductions, then the demand for allowances will be higher than forecast. Thus, an initial oversupply could be consistent with a tighter market later in the program. We intend to return the unsold allowances to auction at prices below the reserve, since we designed the reserve as a source of last resort.
>
> The Board has directed staff to monitor any depletion of the reserve and to make recommendations for modification of the program. We appreciate the concern for the pressures that may be brought to bear if the program must be revised. However, the basic concept for the reserve is that it is not a hard price cap.

Auction Frequency/Schedule

D-2. Comment: The Utilities support the clarifying changes to section 95910(c)(1). (MID4)

Response: No response is needed.

D-3. (multiple comments)
Comment: IETA reiterates its recommendation that purchase limits and holding limits be replaced with more frequent auctions, for example on a monthly basis. Based on recent experience, many will point to RGGI's quarterly frequency and bidding rules as a relatively simple and straight-forward auction design, which is well understood and accessible to a host of entities. While a quarterly auction might be appropriate for small jurisdictions with low demand, IETA believes the implementation of a quarterly auction schedule becomes inconsistent with recent research and analysis conducted in connection with the management of allowance auctions in the EU ETS. Based on analyses, starting in 2013 the EU requires that all regional allowance auctions be conducted on a weekly basis (if not more frequently). The European Commission's decision to hold frequent auctions was driven by the large volume of allowances going to auction in the future, as well as the desire to curb potential price spikes, price volatility, and opportunities for market manipulation. In light of the above, California officials might want to consider timing the frequency of its allowance auctions based on the number of allowances to be auctioned over each period. Weekly auctions are likely to work well in jurisdictions with a large pool of allowances, such as the EU ETS. However, in jurisdictions with constrained coverage and/or large gratis allocations, weekly/monthly auctions could exhibit such small available volumes as to make auction participation high-cost with relatively low-value. IETA welcomes the opportunity to meet with officials to discuss auction design, frequency options and trade-offs. (IETA4)

Comment: Holdings limits are intended to prevent one entity from cornering the market. However, this also places significant strain on many compliance entities. Auction frequency would ostensibly alleviate the concern of one entity concerning the market while creating more liquidity within the market. CCEEB recommends moving towards monthly auctions in order to avoid the need for holding limits. (CCEEB4)

Comment: Increasing the frequency of auctions is the most efficient tool to control the risk of market manipulation. Research included in our August Letter demonstrates that the most effective way to curb the risk of market manipulation is to hold auctions frequently. More auctions reduce the risk of market abuse because of the decreased value at stake in smaller auctions. They also minimize price volatility experienced at the time of allowance auctions and the risk of any one market player exercising excessive market power between auctions. For those reasons, most agencies managing carbon markets have moved to a weekly auction schedule, including in Europe and Germany where, by law starting in 2013, auctions must be held on a weekly basis or more frequently. RGGI is an outlier whose design dates back to 2006/2007. The RGGI quarterly auction schedule has been largely untested, because the RGGI market is historically long (i.e. characterized by excess allowance supply) and trading activity is low. We recommend that ARB use the 2012 auctions to identify any significant issues related to auction frequency and provide an opportunity for all market participants to experiment with the auction process. Starting in 2013, we recommend that ARB move to a monthly, semi-monthly or weekly auction schedule in accordance with the most recent research conducted worldwide on carbon auctions. (CHEVRON5)

> **Response:** The comment is outside of the scope of the second 15-day changes to the regulation. No response is required. Nevertheless, our stakeholder consultations held in 2009 and 2010 brought up other factors affecting our decision to hold quarterly auctions. First, stakeholders did believe that the quarterly format was operating successfully at the time. Second, both stakeholders and ARB were concerned with the ability of all covered entities to participate in frequent auctions due to the costs and time commitments. Some California-covered entities have extensive experience with auctions and commodity markets, and have resources to conduct extensive auction and secondary carbon market participation. Others do not. We believe that retaining the quarterly format will give covered entities time to develop the capabilities for more frequent auction participation. Third, ARB has not operated auctions or financial activities on this scale before, and we must develop the contract services, internal procedures, and enforcement mechanisms needed for successful implementation. We note that the EU ETS auctions are generally conducted by national ministries with extensive experience in market operations. Auctions pose no great institutional challenges for them.
>
> We conclude that the quarterly format can be successfully implemented without damaging the market. At the same time, we do see some value in evaluating a potential move to a more frequent auction once we develop the institutional capability, stakeholders develop familiarity with the process, and we can review a longer period of market information from the EU ETS.

Auction Limitations

D-4. Comment: MSCG largely has no objections to the non-disclosure provisions for auction participants in section 95914(d)(1)(A). However, we do not see the harm to the market that might come from simply revealing that a company has qualified to bid in the auction. It would be normal business practice in many circumstances to simply represent to potential clients and/or customers that MSCG was qualified, and was an eligible market participant, as a way to promote our capabilities when soliciting business. For this reason, we recommend that the prohibition on revealing qualification status be eliminated. (MSCG4)

> **Response:** The case brought up in the comment, that of an entity serving as an advisor, is covered under section 95914(d)(2), not section 95914(d)(1), which covers general auction participants. Section 95914(d)(2) would allow advisors to recruit clients and advise them. However, this comment is outside the scope of the second 15-day changes to the regulation because we have not proposed any

change to the rules governing disclosure of information on auction participation. No further response is needed.

Reserve Supply

D-5. Comment: We understand that it is ARB's intent to fix any problems through the regulatory process or initiate the emergency provision of the Health and Safety Code section 38599, if the reserve is depleted. We believe that the regulatory process may be too time consuming to respond in a timely manner and that relying on the emergency trigger creates undue disruptions and is unwarranted when it can be handled in a less draconian manner through preplanning. CCEEB recommends that ARB identify reserve indicators to monitor and the criteria and process for backfilling the reserve before it is completely depleted. The refill mechanism should trigger once the reserve is 50 percent depleted to bring more supply into the market, recognizing that use of the reserve indicates scarcity in the market and potential liquidity problems. (CCEEB4)

Response: This comment is outside the scope of the second 15-day changes to the regulation because we did not propose any change to the funding of the reserve in section 95870 or add any language on depletion of the reserve anywhere in the regulation. Therefore, no response is needed.

Purchase Limits

D-6. (multiple comments)
Comment: In addition, the Purchase Limit currently establishes a ceiling of 15 percent of the allowances offered per auction. While this proposal would have little, if any, impact on relatively small emitters of GHG, such a proposal for relatively larger emitters or those with corporate associations may create constraints on their ability to choose which auctions to enter, when to purchase allowances from the auction, etc. In recognition of these disparate impacts on Covered Entities, the Purchase Limit should generally remain at 15% of the allowances offered for auction; however, for large covered entities or a group of covered entities with a corporate association, CARB should set the Purchase Limit for these entities such that it recognizes different magnitudes of compliance obligations. IEP believes that this adjustment may only apply to a very small subset of covered entities or a group of covered entities with a corporate association. This amendment should be made to the regulation prior to the first auction in 2012. (IEPA3)

Comment: We reiterate that Purchase Limits (section 95911(c)) should be waived or increase in the event that allowances would otherwise go unsold in an auction. This provision would preserve ARB's stated goal of ensuring "fair and equitable access to allowances sold at auction, "but also allow for a more liquid and efficient market in the event that the auction would otherwise close undersubscribed. (CE2CC2)

Response: We heard similar concerns from covered entities, and we raised the purchase limit from 10 percent to 15 percent for covered entities. The purchase limit continues to apply only to the first compliance period. Based on our reviews of emissions data and consultations, we believe the limit is high enough to allow all covered entities to purchase their emissions needs, net of direct allocations, from the auction. We believe the new limit, together with the existing limit on non-covered entities, does level the playing field.

We are entering a phase of considering linkage with other jurisdictions in the WCI. We anticipate that the calculation of the purchase limit may have to change to reflect the size distribution of emitters and total allowance supply in the WCI. The WCI is discussing alternative ways of setting the purchase limit for a WCI joint auction. As linking will require a new regulatory effort, we will continue to seek advice from stakeholders as the WCI linking is evaluated.

Auction-Bid Guarantee

D-7. Comment: Minimize unnecessary bureaucratic requirements. Investment grade credit-rating should be permitted in lieu of bid guarantees in sections 95912(h) and 95913(e)(2). (CCEEB4)

Response: This comment is outside the scope of the second 15-day changes to the regulation because we did not propose any change to the bid guarantee requirements. No response is needed.

Consignment Auction and Allowance Limits

Purchase Limits

D-8. Comment: The Regulation Should be Revised to Avoid Discriminatory Impacts on Independent Generators Through Application of the Auction Purchase Limits.

The utilities' exemption from the purchase limit should be deleted. The purchase limit on allowances applies to all regulated entities, except electrical distribution utilities. Distribution utilities that purchase allowances to cover their own compliance obligation should be treated the same as any other entity subject to a compliance obligation. Specifically, independent generators directly compete with UOG and this preferential provision could provide an unfair advantage to UOG, especially as allowances become scarcer in the later years of the program. This limitation could also create a skewed competitive playing field where utility distribution companies can obtain more allowances than they need for their own compliance obligation, only to sell back to their IPP competitors when prices are high. When applying the purchase limit to covered entities in a non-discriminatory manner, the purchase limit must be established such that all covered entities face equivalent opportunities to buy (or not buy) out of the auction allowances necessary to meet their compliance obligations. (IEPA3)

> **Response:** This comment is outside the scope of the second 15-day changes to the regulation because we did not propose any change to the exemption of utilities from the purchase limit. No response is needed.

Market Readiness

D-9. Comment: ARB should release a "formal declaration of readiness" at least 60 or 90 days prior to "going live" with their first auction. The CAISO for the Market Redesign and Technology Upgrade underwent this process including system testing by market participants and CAISO ran into some software problems. It is important for ARB to have the same type of formal action to notify market participants. Furthermore, this declaration would be an opportunity for stakeholders to raise to ARB's attention any concerns they may have about the status of the program and readiness to go live. (CCEEB4)

> **Response:** Readiness testing of administrative systems is not part of this rulemaking. However, we will have a readiness testing requirement as part of the contract with the auction system operator. We anticipate that stakeholders, as well as our Market Surveillance Committee of academic experts, will have the opportunity to address to us concerns they may have about the auction platform.

Other Auction-Related Comments

D-10. Comment: PG&E understands the intent of the auction format is for the price to be set at the Auction Reserve Price when there are unsold allowances. However, the current text in section 95911(d)(4) does not ensure this outcome. Further, Section 95911(b)(3), which describes the process for returning unsold allowances, is predicated on there being unsold allowances only when the Auction Settlement Price equals the Auction Reserve Price. This may not always be the case. Assume there are four allowances consigned and there is a single bid for three allowances at $15/allowance. In accordance with section 95911(d)(4), the regulation does not specify what the Auction Settlement Price would be because there is no additional bid below the Auction Reserve Price of $10/allowance. Further, even if the example included an additional bid for two allowances at $5/allowance, the current regulation suggests that the Auction Settlement Price would be the “current price” of $15/allowance instead of the Auction Reserve Price of $10/allowance as intended. PG&E recommends the following changes to address both these possibilities and ensure the auction operates as intended. Modify section 95911(d)(4)(A) as follows:

> (A) The next lower bid price is less than the ~~a~~<u>A</u>uction ~~r~~<u>R</u>eserve ~~p~~<u>P</u>rice <u>or there are no additional bids</u>, in which case the ~~current price~~ <u>Auction Reserve Price</u> becomes the ~~a~~<u>A</u>uction ~~s~~<u>S</u>ettlement ~~p~~<u>P</u>rice; or (PGE5)

> **Response:** While we agree that allowances can remain unsold when the auction settlement price is above the auction reserve price, there is no problem,

because the process of re-auctioning the allowances is not affected. We will consider clarification in future regulatory amendments.

E. COMPLIANCE OBLIGATION / COMPLIANCE CYCLE

Untimely Surrender

E-1. Comment: ARB's clarifications on untimely surrender of compliance instruments in section 95857 are appreciated. The 5 percent flexibility threshold and six-month time period to surrender compliance instruments allow some room to respond to a changing system. However, as this regulatory framework is likely to evolve on several levels, Ag Council requests that ARB consider the remainder of the first compliance period as a grace period for implementation for participants in cap and trade. Participants will be learning more about their technology and the regulatory requirements as the first compliance period begins in 2013, as will ARB staff and enforcement officials. By removing the 5 percent threshold and increasing the six-month timeframe to the end of the first compliance period, it will provide more flexibility for participants and staff to create a system that works for everybody. (ACC5)

> **Response:** We disagree. We effectively already allowed our emitters a grace period for their GHG emissions in 2012 by removing the compliance obligation for that year. To make sure that the cap-and-trade program properly incentivizes reductions, it would be inappropriate to further extend that grace period. Emitters have had time during 2011, and will have further time in 2012, to learn more about their technology.

E-2. Comment: Section 96014(b) refers to the "Untimely Surrender Period." However, this term is not defined and is not used elsewhere in the Regulation. In order for covered entities to be aware of the circumstances in which this penalty provision will apply, it is important to replace this term with a reference to the relevant section of the Regulation, which is section 95857(b)(6). This change can be made without further 15-day public comment, as it is "nonsubstantial or solely grammatical in nature" for the purposes of section 11346.8(c) of the Government Code. Modify section 96014(b) as follows:

> (b) A separate violation accrues every 45 days after the <u>date determined pursuant to section 95857(b)(6)</u>~~end of the Untimely Surrender Period~~ for each required compliance instrument that has not been surrendered. (SCPPA8)

> **Response:** For further clarification, we added a reference to section 95857 for section 96014(b).

E-3. Comment: NCPA supports the Proposed Revision to section 95857(b)(4) that would allow compliance entities to meet one-quarter of their untimely surrender obligation with offsets, rather than requiring only allowances to be surrendered. In section 95857(b)(6), NCPA continues to urge CARB to allow at least two weeks (or 10 business days) between the first auction or reserve auction following the surrender date and the deadline for surrendering the untimely obligation. (NCPA4)

Response: We disagree. We believe that the five days provided in section 95857(b)(6) provides emitters ample time to meet their compliance obligations.

E-4. Comment: As required in section 95857, making up excess emissions at a 4:1 ratio is a good deterrent. However, the rules are structured so that this is not due until five days after the next auction or reserve sale conducted by CARB. This presumes that these will be the only mechanisms for market participants to obtain compliance instruments and may introduce unnecessary delays in obtaining the make-up compliance instruments. We suggest that the excess emissions be due in 30 days, and then appropriate additional enforcement action can be taken for delays. (SCAQMD5)

Response: We disagree. We do not presume that the auction and reserve sale will be the only mechanisms for emitters to obtain compliance obligations. However, we want to make sure that emitters have access to these mechanisms. Thus, the regulation provides emitters the opportunity to access at least one of these mechanisms before the deadline to comply with an untimely surrender obligation.

E-5. Comment: While section 95858 provides for a notification from ARB when there has been under-reporting, there does not appear to be the same notification in section 95857. Instead, there is a reference to an "assessment" (without reference to notification to the regulated entity) which triggers a short window to purchase additional allowances before a penalty of four times the missing allowances is required. (UNITEDAIRLINES3)

Response: This comment correctly notes that section 95857 does not require ARB to "notify" those with an untimely surrender obligation for their new obligation. Rather, the new obligation is "assessed." Section 95858 specifies that we notify any emitters of a compliance obligation for underreporting. In part, this is because underreporting requires ARB to make a determination. By contrast, there is far less expertise needed to determine whether there is an untimely surrender obligation. It should be readily apparent to each emitter whether they surrendered enough compliance instruments to comply with their original compliance obligation.

E-6. Comment: While the amendments made to the regulation now allow for up to one fourth of an entity's compliance obligation for untimely surrender to be filled with ARB offset credits, rather than solely with GHG allowances (section 95857(a)(4)), the framework of the untimely surrender obligation still penalizes entities that are in compliance with the cap-and-trade program by creating allowance supply constraints. Currently, the cap-and-trade regulation requires that covered entities that do not retire the requisite number of allowances for their triennial compliance obligation will be subject to an "untimely surrender obligation" for the shortfall. The untimely surrender obligation is four times the shortfall and must be satisfied by submitting allowances or offsets in order to satisfy the untimely surrender obligation. As a result, there will be significantly more demand in the auction for allowances, creating upward pressure on prices. Due to the high allowance prices resulting from this heightened demand in the auctions, covered entities that are in compliance with the cap-and-trade program will inappropriately be penalized, in the form of higher prices for GHG allowances, for the actions of others who were not in compliance. To avoid penalizing complying entities, CARB should require the entity subject to the shortfall to obtain allowances for its compliance obligation (i.e., 1/4 of the untimely surrender obligation), thereby avoiding the price effect of increased demand for allowances and maintaining the integrity of the "cap." On the other hand, the same entity should be required to meet the rest of the penalty (i.e. 3/4 of its untimely surrender obligation) via a financial payment, based on the auction clearing price, to be paid to the Air Pollution Control Fund. (IEPA3)

> **Response:** We disagree. We carefully considered the merits of the two approaches to require extra allowances or a financial payment for a compliance obligation that is not met within the specified time. We consulted with experts from other cap-and-trade programs and with our Western Climate Initiative (WCI) partners. Following those consultations, we concluded that the approach requiring additional compliance units was the most appropriate for California. If an entity surrenders additional compliance instruments because of an untimely surrender, one of those compliance instruments is retired (if offsets are submitted, the offsets would be retired), and the remaining instruments are placed into a future auction.

E-7. Comment: While the Utilities continue to believe that the eight percent overall limit on the use of offsets provides sufficient protection to ensure real and permanent GHG reductions, we support and appreciate the changes in section 95857(b) which will allow one-fourth of an entity's Untimely Surrender Obligation to be fulfilled with offset credits. (MID4)

> **Response:** Thank you for your support.

Timely Surrender

E-8. Comment: Section 95856(b)(2) of the regulation states, that "To fulfill any compliance obligation, a compliance instrument must be issued from an allowance budget year within or before the year during for which an annual the compliance obligation is calculated, or the last year of a compliance period for which a triennial compliance obligation is calculated, (. . .)" We think that the wording does not clearly say which allowances can be used for the triennial compliance obligation. The paragraph should be altered so that it becomes obvious if allowances only from the corresponding vintage year or allowances from the corresponding compliance period can be surrendered. (TSG)

> **Response:** We disagree. We believe the wording is clear. For an annual compliance obligation, allowances from that vintage or an earlier vintage may be used. For a triennial compliance obligation, allowances from the final vintage of the compliance period or from any earlier vintage may be used.

E-9. Comment: CLFP supports emissions borrowing. The current regulation only allows emissions banking in the cap-and-trade. CARB should allow borrowing allowances with some limits and standards. The ability to borrow will aid in reducing costs and allow companies to meet obligations without penalty for short periods of time. (CALFP4)

> **Response:** We disagree. After consultation with experts from other cap-and-trade programs and with our WCI partners, we decided not to allow borrowing.

Under-Reporting

E-10. Comment: The Utilities support the inclusion of an eight-year statute of limitations on the determination of under-reporting in section 95858(d). (MID4)

> **Response:** Thank you for your support.

E-11. Comment: The Second 15-Day Revisions clarify that the compliance obligation associated with underreporting in a previous period (found in section 95858) are not subject to the untimely surrender obligation (section 95857) or direct penalty provisions (section 96014) if the obligation is met within six months. The Proposed Revisions would also place an eight-year limit on the look-back period for underreporting. NCPA supports these proposed changes for inclusion in the Cap-and-Trade Regulation and urges CARB to adopt them. (NCPA4)

> **Response:** Thank you for your support.

E-12. Comment: We were surprised to see the addition of language in section 95858(d) which states that the ARB can go back eight years in determining whether there has been under-reporting of emissions. This is much longer than the time period provided for under most federal and state environmental regulations. The reason for shorter periods under many laws is the fairness of seeking to defend against such an enforcement action after a significant amount of time has passed. While there is an obligation to maintain records under the Cap and Trade for ten years, there can be related communications and documents which would serve to provide context to the circumstance, along with the potential for faded memories and changes in applicable personnel. We would ask that ARB re-consider inclusion of this enforcement time period in the cap-and-trade regulation. (UNITEDAIRLINES3)

> **Response:** We appreciate the concern. However, we believe that the eight-year provision is appropriate. It is also supported by some stakeholders (see above). As the program moves forward, we will continue to evaluate this provision and other provisions in the regulation.

E-13. Comment: Section 95858(d) was added, which states that a facility is not held responsible for under-reporting emissions if CARB has not taken action for inaccurate emission reporting after eight years. This usually is an adequate period of time for a regulatory agency to discover the violation, investigate and take appropriate enforcement action if necessary. However, three-year compliance periods, along with a period of six months to make up under-reported emissions, may allow facilities to escape liability for what could be significant violations. (SCAQMD5)

> **Response:** We acknowledge the concern. We believe that eight years strikes the appropriate balance allowing us to enforce against under-reporting but also providing emitters some certainty that enforcement action will not be taken for actions that are from a more distant past.

E-14. Comment: In section 95858(a), we are very concerned that the provision of a five percent "free" under-reporting will introduce a potentially significant failure of the market to reach its required goals. The Mandatory Reporting rules also allow up to three percent of emissions (up to 20,000 MT CO_2e) to be considered "de minimus" with less rigorous reporting requirements, which compounds this potential problem to potentially allow up to eight percent under reported emissions. For larger emitters these percentages can be a substantial amount of emissions. In addition, the formula in the rule does not represent an adequate deterrent against under-reporting. Under-reported emissions should also be made up at a 4:1 ratio, if a shortfall occurred, regardless of whether it was from under-reporting or not surrendering enough compliance instruments to cover reported emissions. Six months is also too long to make up the shortfall. This should be shortened or left to CARB discretion considering the amount of emissions due. RECLAIM requires reconciliation within 30 days for quarterly reporting periods and 60 days for the annual period. (SCAQMD5)

> **Response:** We disagree that the provisions against under-reporting need to be strengthened. We believe they are appropriate. The six months allows enough time for entities to participate in an auction or reserve sale to acquire additional compliance instruments. The five percent in the formula is consistent with how reported emissions are reviewed during verification. The commenter is mistaken in how they have pulled several parts of the MRR and cap-and-trade requirements together to conclude the program is not designed to deter under-reporting. Independent of the additional compliance instruments needed for cap-and-trade, the MRR has very stringent penalty provisions to address under-reporting. The two rules work together to build a strong program without “layering” penalties for the same issue.

E-15. Comment: In section 95858(c) it is unclear why "subsequent" year compliance instruments are usable for correcting under-reporting, when they are not usable for the original obligation. This could encourage facilities to deliberately under-report emissions. At a minimum, we suggest that the "subsequent" years be limited to the year in which the under-reporting obligation is being satisfied. (SCAQMD5)

Response: We acknowledge that allowing "subsequent" vintage years could encourage facilities to deliberately under-report emissions. However, we believe this is approach is the most appropriate. Requiring allowances from the compliance period with under-reported emissions could be an issue. For example, if midway through the third compliance period an under-reporting issue was discovered for an emitter in the first compliance period, it may not be possible to find allowances from the first compliance period, since allowances banked from the first compliance period may have been used to meet compliance obligations from the second compliance period.

Compliance Obligation

E-16. Comment: Section 95853 states that a covered entity that initially exceeds the threshold in section 95812 in the first year of a compliance period is a covered entity for the entire period. ARB should allow compliance instruments issued from an allowance budget throughout a triennial compliance period be available for use to meet a triennial compliance obligation not just the last year of a compliance period for which a triennial compliance obligation is calculated as stated in Section 95856(b)(2). Valero does not believe that ARB's intent was to limit the use of compliance instruments for a triennial compliance period to those compliance instruments issued during the last year of the triennial period. The language in Section 95856(b)(2) is confusing and Valero recommends that the language be changed to match the language that is used in the Summary of Proposed Modifications. Modify section 95856(b)(2) as follows:

> (2) Compliance instruments issued for the last year of a compliance period, or from a previous vintage, may be used for a triennial obligation, for that compliance period. ~~To fulfill any compliance obligation, a compliance instrument must be issued from an allowance budget year within or before the year for which an annual compliance obligation is calculated, or the last year of a compliance period for which a triennial compliance obligation is calculated, unless:~~ (VALERO3)

> **Response:** We made a minor grammatical edit to section 95856(b)(2) to clarify which vintage allowances may be used to meet a triennial compliance obligation.

Exemption for Federal Agencies

E-17. (multiple comments)
Comment: We respectfully request the regulations remove the limits on our participation and regulation include, but are not limited to, the following:

- Provide Federal facilities an initial allowance budget with a modestly declining balance over the three compliance periods and provide Federal facilities with appropriate mechanisms to allow compliance in the case of a national emergency or military operations outside of normal day-to-day operations; or

- Add “NAICS 928110 National Security” to “Table 8-1: Industry [and Military] Assistance” and expand the related discussion to include national security activities. The expanded discussion could address the fact that military installations may not have the benefit of moving across state lines to minimize regulation due to their extensive infrastructure investments in close proximity to existing airspace and ranges in California. It could also address the fact that the military cannot pass along the cost to consumers, and without equitable assistance, the cost to taxpayers either increases or training and readiness activities suffer. (USDOD3)

Comment: The Marine Corps hereby incorporates by reference comments made in the following correspondence:

- January 20, 2010 (DoD Comments on Preliminary Draft Regulation)
- December 14, 2011 (DoD Comments on Proposed Regulation Order)
- June 28, 2011 (Supplemental Legal Analysis (attached to Comment 49)
- September 16, 2011 (Assistant Secretary of the Navy Letter to Chair, ARB (attached to Comment 47).

Finally, while we generally support the ARB's recognition of issues unique to the military, we respectfully renew our request for a permanent exemption from compliance obligations. (MCAGCC)

Comment: Specific to the California cap and trade program, we are extremely concerned with the regulations implementing AB 32, as fiscal and constitutional law presents barriers to federal participation. I strongly support the DoD Regional Environmental Coordinator’s current proposed language seeking permanent regulatory relief, and would request that ARB give it careful consideration. (USDON)

Comment: Allowing the DoD to address GHGs through its own internal planning allows for a more comprehensive approach and it gives flexibility to the commanders of troops on the ground to determine how to achieve reductions without compromising National Security. It is important to note that while the federal plan achieves greater GHG reductions, those reductions might not derive solely from facilities that exceed the cap-and-trade applicability threshold. The SSPP does not guarantee any one facility will meet the same goals as cap-and-trade, but it does guarantee that GHG mitigation goals will be achieved across DoD. (USDOD3)

Comment: Before these regulations become final, we hope you will strongly consider either modifying them to remove the legal constraints of our participation or acknowledge that federal facilities have no compliance obligation under the regulations as they are currently drafted by including one of the following new provisions. Modify section 95852.2(g) or add section 95815 as follows:

> (g) Emissions from Federal Facilities that meet the definition of a covered entity as set forth in Subsection 95802(a)(44).

Section 95815. Military Facilities. Military facilities that qualify as a "covered entity" pursuant to Section 95811 and that exceed the applicability threshold herein are exempt from this regulation. (USDOD3)

Response: We continue to work with the Department of Defense's representatives to resolve concerns that they have raised. The second 15-day changes to the regulation provided a new exemption in section 95852.2(c). We do not believe it is appropriate to further modify the regulation at this point for how they may participate in the cap-and-trade program, but we will continue to work with them for how we modify the regulation in the future. Board Resolution 11-32 directs the Executive Officer to coordinate with stakeholders to develop a mechanism to achieve GHG emission reductions from the national security/military sector (NAICS 92811) beginning January 1, 2014.

Transportation Fuels

E-18. (multiple comments)
Comment: Transportation fuels are not covered under the cap and trade program until the second compliance period. Since hydrogen is a low-carbon fuel, the carbon footprint of its production is equivalent to a conventional fossil fuel's carbon footprint during use. As such, hydrogen used as a transportation fuel during the first compliance period should be exempt from a compliance obligation, consistent with the absence of a compliance obligation imposed on fossil-fuel based transportation fuels during the first compliance period. The hydrogen fuel exemption would also be consistent with the lack of a compliance obligation for natural gas used as a transportation fuel during the first compliance period. This temporary exemption can be realized by CARB allowing a reduction in a hydrogen producer's overall compliance obligation proportional to the fraction of total production which is sold as a transportation fuel. Alternatively, CARB could make an allowance allocation equal to the emissions associated with the amount of such hydrogen produced and sold as transportation fuel. (APC3)

Comment: Hydrogen produced for use as a transportation fuel should be exempted from a compliance obligation until the second compliance period. (IGPACC2)

Response: We recognize the potential of hydrogen as a clean transportation fuel. However, we do not agree that it is appropriate to exclude from a compliance obligation or to provide an explicit incentive for this use of hydrogen through free allocation. The purpose of allowance allocation is not to "pick winners" among the many greenhouse gas-reducing technologies that may become more widely used in response to the carbon price signal created by the cap-and-trade program.

In addition, we modified the regulation to allow for a different allocation to liquefied hydrogen production facilities in the future if necessary. If, in the future, any carbon costs from purchased electricity are included in consideration of the product benchmark values, the high level of indirect emissions from liquefaction of the hydrogen would likely lead to a different benchmark value for liquefied hydrogen. The current framework could also allow for a change in the leakage risk classification for liquid hydrogen based on any new information that may arise as we continue to analyze leakage risk per the direction in Board Resolution 10-42 and Resolution 11-32.

E-19. (multiple comments)
Comment: Our recommendation is that fuels not be included under the cap. Including fuels under the cap is redundant with the low carbon fuel standard and vehicle mileage standards. As presently structured treatment of fuels under the cap is inequitable relative to treatment of utility power. The cost to producers and for consumers of fuels will be excessive. (TESORO3)

Comment: The inclusion of transportation fuels under the cap beginning 2015 should be re-visited. The economic impacts of California-only fuels under the program should be further evaluated, including cost and consideration for the fact that California is already implementing the Low Carbon Fuel Standard (LCFS). (CALCHAMBER4)

Comment: We also believe treatment of fuels-under-the-cap issue needs to be revisited. The Scoping Plan proposed inclusion of transportation fuels in the cap-and-trade program beginning in 2015, largely due to the expectation that Western Climate Initiative states would address fuels this way in their state programs. Since California is already implementing the Low Carbon Fuel Standard, and no WCI states are prepared to link to California, we recommend that the leakage impacts of a California-only fuels-under-the cap (on top of the LCFS) be re-examined. Since CARB does not intend to implement Fuels under the Cap until the 2015-2017 compliance period, it is important for CARB to take the opportunity now to assess all available alternatives in addressing transportation fuels in a simple and comprehensive framework under AB 32. (AB32IG3)

Response: The cap-and-trade regulation will help transition California away from carbon-intensive fossil fuels to cleaner and more-efficient fuels. The fossil fuel portions of biofuels and bioenergy are under the cap. Transportation fuels and fuel suppliers will have a compliance obligation. However, biomass-derived fuels are exempt from a compliance obligation, since CO_2 emissions resulting from the combustion of biomass are considered biogenic. Emissions from biomass-derived fuels must be reported and verified pursuant to the MRR. Source categories that are not listed under section 95852.2 (Emissions without a Compliance Obligation) or that have not received a qualified positive or positive verification statement must be reported as “other biomass CO_2.” Other biomass emissions that cannot be verified pursuant to the MRR are not considered biomass-derived, and will hold a compliance obligation.

Furthermore, California’s Low Carbon Fuel Standard (LCFS) addresses all lifecycle emissions (not just fossil fuel) in its regulation. The LCFS also plans to reduce the carbon intensity of transportation fuels 10 percent by 2020. Since

GHG lifecycle emissions from transportation fuels are already regulated through the LCFS, biofuels do not need to be addressed in cap-and-trade regulation. California's LCFS comes from Executive Order S-01-07, which mandates that a statewide goal is established to reduce the carbon intensity of California's transportation fuels by at least 10 percent by 2020. This standard applies to all transportation fuels unless otherwise noted in the law. Specifically with regard to transportation fuels, ethanol from biomass (Agriculture, Municipal, and Forestry) is covered under the LCFS, while biomass electricity is excluded from the regulation. As noted in the LCFS regulation, "The California Low Carbon Fuel Standard regulation, title 17, California Code of Regulations (CCR), sections 95480 through 95490 (collectively referred to as the "LCFS") applies to any transportation fuel, as defined in section 95481, that is sold, supplied, or offered for sale in California, and to any person who, as a regulated party defined in section 95481 and specified in section 95484(a), is responsible for a transportation fuel in a calendar year."

Biomass/Biofuels

E-20. Comment: CERP appreciates ARB's modifications to section 95852.1.1(a)(2), which clarify the circumstances under which biogas may have a purchasing contract dated on or after January 1, 2012. Allowing the conversion to beneficial use through the recovery of fuel will be a helpful incentive for facilities to create useful energy transfer from biogas. CERP supports ARB's approach of allowing a later contracting date where there is "an increase in the biomass derived fuel production, at a particular site." (section 95852.1.1(a)(2)(A)). This provision makes sense because an overall increase in fuel production from a particular site is distinguishable from a "resource shuffling"-type scenario. However, section 95852.1.1(a)(2)(A) has some ambiguity because it measures the "increase" in terms of "any amount over the average production at that site over the last three years." It is not clear whether this language applies in the case of a newly constructed facility. One valid interpretation of this phrase is that production from a new facility would qualify as an increase because there would have been zero "average production" from the "particular site" in the previous three years. It would be very helpful if ARB, in the Final Statement of Reasons, clarified that this interpretation of section 95852.1.1(a)(2)(A) is valid. Alternatively CERP recommends that ARB clarify the regulations in the next rulemaking by modifying section 95852.1.1(a)(2)(A) to state "an increase in the biomass derived fuel production capacity, at a particular site or a new production facility …" (CERP5)

Response: The interpretation above is incorrect because provision 95852.1.1(a)(2)(A) reads that the increase would have to be over the average production within the last three years. There are two options for fuel being provided under a contract dated on or after January 1, 2012. The second provision (95852.1.1(a)(2)(B) states that the fuel being provided must only be for an amount associated with recovery of the fuel at a site where the fuel was previously being vented or destroyed without producing useful energy. We will continue to evaluate this issue and consider rule modifications as part of a separate rulemaking.

E-21. (multiple comments)
Comment: CERP has noticed a contradiction between section 95852.2(a)(8), which states that biomethane and biogas from all animal, plant and other organic matter, as well as landfill gas and wastewater treatment plants, do not count toward an entity's compliance obligation, and section 95852.1.1, which requires that the biogas fuel have a contract for purchasing prior to January 1, 2012. CERP recommends that in the next rulemaking ARB modify section 95852.2(a)(8) to state: "Biomethane and biogas that is eligible under section 95852.1.1, as applicable, and from the following sources." This will clarify that in order to be eligible for the compliance exemption biogas must adhere to applicable regulations. (CERP5)

Comment: Camco is concerned that as currently written the regulations would not permit gas from a new biogas facility to earn a compliance exemption for the emissions produced when that gas is destroyed (section 95852.1.1). The construction of new biogas facilities represent an overall increase in the amount of biogas, not resource shuffling. Contracts for purchasing biogas from a newly constructed facility should be able to receive a compliance exemption, and such biogas should also be able generate RECs and offset credits. Under the current regulations, it appears this may be the case, but it is not clear. To clarify this position for developers, Camco hopes that ARB can provide further clarification in its Final Statement of Reasons. Furthering this uncertainty is the contradiction between section 95852.2(a)(8), which states that biomethane and biogas from all animal, plant and other organic matter do not count toward an entity's compliance obligation, and section 95852.1.1, which requires that the biogas fuel have a contract for purchasing prior to January 1, 2012. (CIG3)

> **Response:** The regulation language states clearly that emissions from the source categories and from the combustion of the fuel types listed in section 95852.2 count toward applicable reporting thresholds, as applicable in the MRR, but do not count toward a covered entity's compliance obligation. These emissions include CO_2 emissions from: combustion of biomethane and biogas from animal, plant, and other organic waste, or from landfills and wastewater treatment plants.

E-22. Comment: CERP further supports the modifications to section 95852.1.1(a)(1)(C) that allow for flexibility in the contracting date by counting the date that an entity submits an application to CEC as meeting the requirements for January 1, 2012 contracting date. However, the requirement that gas start to flow 10 days after the completed CEC application may not reasonable for some purchasers depending on the contractual structure in place, and CERP requests that the period be extended to 30 days. (CERP5)

> **Response:** We revised section 95852.1.1(a)(1) to specify that a contract for purchasing any biomass-derived fuel must be executed prior to January 1, 2012.

Prior versions of the regulation had stated that contracts must have been in effect prior to January 1, 2012.

E-23. Comment: CERP commends ARB for its efforts to clarify section 95852.1.1(b) to make it clearer that offset credits can be generated from projects without removing their compliance exemption. However, the provision is still very difficult to parse. It would be helpful if ARB offered an explanation of the provision in the Final Statement of Reasons. CERP's understanding is that this section provides for the following:

- Credits and allowances are not available for CO_2 emissions associated with combustion of biomethane, biogas, or other biomass-derived fuel (or the reduction in CO_2 emissions associated with use of fuel for energy instead of the flaring of that biomethane or biogas); provided that
- Credits may be available for avoided methane emissions associated with biomethane or biogas produced from digesters or landfills pursuant to the relevant offset protocols. Such credits may not exceed 23.75 metric tons of CO_2e per ton of captured (or avoided) methane.
- Nothing in section 95852.1.1 prevents the generation of Renewable Energy Credits associated with biomass-derived fuels. (CERP5)

Response: We clarified the text to allow for biogas from a digester offset project to be exempt from a compliance obligation for its combustion emissions. The offset project only credits the capture and destruction of methane. The exemption applies to the combustion CO_2.

E-24. Comment: Modifications made to section 95852.1.1(b) go some-way to making ARB's intention on the offset and other environmental credit biogas facilities may earn clear. However, Camco feels that this language could be made clearer and/or accompanied by an explanation in the Final Statement of Reasons clarifying the intent and meaning of the regulation. As Camco understands the regulation, ARB intends to permit biogas facilities to generate offsets equivalent to the GHG emissions avoided through the installation of a digester or cap to capture methane which would have otherwise been emitted and permit the facility to generate Renewable Energy Credits from the generation of energy through use of the gas. However, offset credits are not available for CO_2 emissions associated with the combustion of the biogas. (CIG3)

Response: We do not believe a change is necessary. The regulation allows CO_2 emissions from biogas from a landfill participating in the voluntary offset program to be exempt from a compliance obligation if used at a covered entity in lieu of a fossil fuel.

E-25. Comment: The proposed modifications include no changes in response to our previous comments that GHG emissions from the combustion of woody biomass should be included under the cap and generate compliance obligations. "Entities combusting these fuels should be excused from compliance obligations only to the extent that they can demonstrate that the production and use of the biomass fuel resulted in reduced or avoided greenhouse gas emissions over a timeframe relevant to AB 32, that is, by 2020." That is, any exemption from compliance obligations must be based on an explicit and source-specific determination of the GHG emissions associated with the production and combustion of the feedstock. In the case of forest biomass, such a determination would need to take into account fuel characteristics and sources, secondary emissions associated with harvesting and processing, land use impacts, and effects on future sequestration. The blanket exemption proposed in both the original draft regulation and the proposed modifications satisfies none of these criteria, and thus lacks any evidentiary basis. From our numerous conversations with ARB staff on this topic we understand that ARB remains committed to this blanket exemption for the GHG emissions associated with the combustion of woody biomass. To date, however, ARB has not presented any analysis or evidence to support this approach. As our December 15, 2010 comments and the numerous scientific articles and studies attached thereto demonstrated, there is no basis in scientific fact for treating GHG emissions from biomass as if they have no effect on the climate. Indeed, the scientific evidence against such an approach to biomass carbon accounting continues to mount. For example, a recent paper released by the Scientific Committee of the European Environment Agency directly contradicts and warns against this type of blanket exemption for the GHG emissions from the combustion of plant biomass. "It is widely assumed that biomass combustion would be inherently 'carbon neutral' because it only releases carbon taken from the atmosphere during plant growth. However, this assumption is not correct and results in a form of double-counting, as it ignores the fact that using land to produce plants for energy typically means that this land is not producing plants for other purposes, including carbon otherwise sequestered. If bioenergy production replaces forests, reduces forest stocks or reduces forest growth, which would otherwise sequester more carbon, it can increase the atmospheric carbon concentration. If bioenergy crops displace food crops, this may lead to more hunger if crops are not replaced and lead to emissions from land-use change if they are. To reduce carbon in the air without sacrificing other human needs, bioenergy production must increase the total amount of plant growth, making more plants available for energy use while preserving other benefits, or it must be derived from biomass wastes that would decompose and neither be used by people nor contribute to carbon sequestration." (EEA at 1, italics added.) "Proper accounting needs to reflect not merely the loss of existing carbon stocks in the pursuit of biomass production for energy, but also any decline of carbon sequestration that would occur in the absence of bioenergy use. For example, forests worldwide, but particularly in the northern hemisphere, are accumulating biomass and carbon for a variety of reasons, and this growth absorbs carbon from the atmosphere. Some estimates of bioenergy potential suggest that biomass reduces greenhouse gas emissions so long as it only harvests this net forest growth and leaves the carbon stocks of the forests stable. But merely keeping carbon stocks stable ignores the additional carbon sequestration that would occur in the absence of wood harvest for bioenergy (the counterfactual) and therefore does not make bioenergy carbon neutral. For this reason, sustainable forestry in the traditional sense does not necessarily mean that bioenergy produced from a forest is carbon neutral." (EEA at 5, italics added.) ARB has never explained its proposal to adopt a complete exemption from compliance obligations for this category of greenhouse emissions. The facts, however, are clear: leaving all biomass emissions outside the cap, exempt from any compliance obligation whatsoever, ignores the physical realities of biomass production and combustion. This exemption will result in uncontrolled greenhouse gas emissions above and beyond the cap, and thus will interfere with the goals and purpose of AB 32. ARB has no authority to adopt regulations that conflict with fundamental statutory goals. In short, the biomass exemption is arbitrary, capricious, and lacking in evidentiary support. ARB's failure throughout this year-long process to explain its decision to adopt this exemption also flies in the face of clear statutory procedural requirements. We urge ARB once again to refrain from adopting this unlawful, unscientific, and unwise exemption. (CBD5)

> **Response:** ARB wants to correctly identify and separately treat biomass-derived fuels from fossil fuels. Section 95103(j) of the MRR states that the operator or supplier must separately identify, calculate, and report all direct CO_2 emissions resulting from the combustion of biomass-derived fuels as specified in section 95115 for facilities, and sections 95121-95122 for suppliers. Biomass-derived fuel emissions must be identified by the source of fuel, as described in section 95852.2 of the cap-and-trade regulation. A biomass derived fuel not listed in that section will be required to hold a compliance obligation under section 95852.1. For a fuel listed under section 95852.2, reporting entities must also meet the verification requirements in section 95131(i) of this article, or the fuel must be identified as an Other Biomass-Derived Fuel and be subject to a compliance obligation under section 95852.1. By not including biomass-derived fuels under the cap, we are recognizing that the use of a biomass-derived fuel is preferred over the use of fossil fuels at capped sources for the purposes of achieving the AB 32 emissions target.
>
> The scope of this regulation is to apply a compliance obligation on direct emissions from capped entities. Any lifecycle analysis of biomass-derived fuel and its potential emissions or impacts beyond the emissions at the capped entities is not within the scope of this regulation. The program will include transportation fuels under the cap starting in 2015; therefore, GHG emissions associated with the transport of biomass material will be covered under the cap. As described in the Adaptive Management Plan that the Board approved in Resolution 11-32, we are committed to monitor and adjust the program for unanticipated adverse impacts as a result of projects under the U.S. Forest Protocol. We do not believe that exempting emissions from combustion of woody biomass will result in the harmful removal of woody biomass from forests, as there are existing environmental protection laws that serve to protect against the denuding of the forests. The data collected under the MRR will help ARB monitor increases in biomass-derived fuels, types of specific fuels, and source location to monitor for any changes to the use of biomass-derived fuels as a potential result of this program. The reporting requirements in the MRR have been subject to a public review and comment process as part of that rulemaking.

Municipal Solid Waste

E-26. (multiple comments)
Comment: Inclusion of WTE facilities in the CARB Cap and Trade Program ignores the scientifically recognized GHG benefits of this technology and will ultimately result in more landfilling and more GHG emissions generated in California. Covanta Energy and the communities it partners with support a compliance obligation exemption for the three existing Energy-from-Waste facilities in California. An exemption is consistent with the major cap and trade systems currently in place (EUETS or RGGI). Our request is based on the conservative analysis that demonstrates that GHG emissions will increase from landfills if these facilities are included in the cap. Additionally, the communities will lose the electricity revenues generated from the sale of electricity at these facilities. These are revenues that these communities use to fund their recycling programs. In July 2011, CARB concurred, concluding that inclusion of the three WTE facilities in the cap and trade program could increase state-wide GHG emissions. Subsequently, CARB has reversed its assessment. First relying on an unfinished model in a manner completely inconsistent with its intended purpose, and then second relying on a brief spreadsheet calculation that misapplies its own regulation. CARB's abrupt policy reversal, based on the misapplication of a draft model and a cursory spreadsheet calculation resulting in a position contrary to a significant body of international and domestic policy and research, is, to put it mildly, concerning. As a direct consequence, we sincerely request that CARB defer compliance obligations under AB 32 for the three existing municipal waste to energy facilities at least until such time that an external non-conflicted expert panel has provided an approach to calculate the lifetime methane emissions associated with the disposal of municipal solid waste in landfills, taking into consideration CARB's existing analysis and all other relevant available information, and CARB has had an opportunity to apply that approach to satisfy all the risk of leakage resulting from the inclusion of waste to energy facilities in the proposed cap and trade program. (COVANTA2)

Comment: British Columbia has a history of following California's leadership on climate mitigation related initiatives. As a member of the Western Climate Initiative, British Columbia has already passed enabling cap and trade legislation (Bill 18). If the government of British Columbia decides to fully implement a Cap and Trade system, it will almost certainly look towards regulatory guidance from California. As such, ongoing deliberations regarding California's Cap and Trade Program will also have profound influence on other jurisdictions. A number of landfills in British Columbia are reaching capacity. As a consequence, several regions, including Metro Vancouver and the Capital Regional District, have begun to explore other options for dealing with their solid waste. Metro Vancouver recently completed an extensive assessment process and recommended a plan to the Province of British Columbia that was subsequently approved. The plan called for the introduction of substantial waste diversion, recycling and composting programs together with waste-to-energy (WTE) for the remaining solid waste. Metro Vancouver cited that an important reason for moving to WTE was its substantive GHG mitigation potential relative to landfills, even with existing methane capture technology. For reasons that are entirely unclear, California appears to have taken the odd position of including WTE in their cap and trade legislation while excluding landfills. This suggests that WTE is being treated as being part of the energy sector instead of being considered within the solid waste sector. This makes little sense as an internationally recognized means of reducing greenhouse gas emissions ends up being assigned punitive regulatory measures. In addition, a life cycle analysis of WTE within a cap and trade system would need to account for avoided methane emissions from landfill, avoided CO_2 emissions from fossil fuel energy sources, and other avoided GHG emissions associated with the recovery and subsequent recycling of metals. At the same time, it makes little sense to treat emissions within the solid waste sector separately from each other. Under the United Nations Framework Convention on Climate Change common reporting format for the national GHG inventories, waste sector emissions are listed together. Given California's influence on environmental regulation both within the U.S. and Canada, it is extraordinarily important for potential inconsistencies in the treatment of sectoral emissions to be dealt with prior to finalizing California's cap and trade system. The differential treatment of WTE versus landfill emissions is inconsistent with international standards. It will likely have the unfortunate and ironic consequence of encouraging enhanced GHG emissions within the waste sector. (UOV)

Comment: The Sanitation Districts Board of Directors unanimously adopted the enclosed Resolution in response to the sudden change to the proposed rule, regarding waste-to-energy facilities. This action was contrary to your Board's December 2010 Resolution concerning these facilities. The Sanitation Districts request removal of waste-to-energy facilities from the proposed program. The Sanitation Districts are co-owners, with the host cities if Long Beach and Commerce, of two waste-to-energy facilities. The new costs which your proposed rule will impose on the facilities will be a significant burden, and could well result in shutdown of one or both, and elimination of all employee positions (green jobs). In addition, the post-recycled solid waste now used to directly produce energy would instead be diverted to landfills for disposal. (LASD4)

Comment: The Coalition has serious concern regarding the Board's changed position in which WTE facilities will now be subject to the proposed regulations' CO_2e allowance purchase requirement, which is contrary to the Board's previous recognition that imposing such a requirement on WTE facilities would increase waste diversion to landfills and result in more rather than fewer GHG emissions in California. We understand that Board staff are now suggesting two alternative rationales to justify the Board's about-face. The first rationale is a hybrid approach that uses the CALMIM model's hypothetical oxidation rate for uncollected landfill methane, and, based on the Board's analysis, typically approaches 100 percent oxidation. The second rationale is based on the assumption that landfill methane collection systems will continue to operate for up to 260 years post-closure. Both of these suggested rationales are invalid as well as contradictory. First, the CALMIM Model's 100 percent oxidation rate is irrational. A life cycle comparison of the GHG impacts of landfills versus WTE requires, an estimate of the landfill methane that would result if a given quantity of waste is diverted from WTE processing to landfilling. One component of that estimate is the amount of methane that is oxidized within the landfill cover and never released to the atmosphere. The widely accepted standard value for such oxidation (in fact, the method used by ARB in its own regulations for control of landfill methane) is 10 percent oxidation. Instead, the Board is relying on its new hybrid approach that uses the CALMIM model to determine fugitive methane emissions post-closure with no landfill gas collection system in operation. Aside from the fact that the CALMIM model is apparently still in development and has a number of technical problems that require correction, CALMIM (as used by ARB to compare life cycle GHG impacts of landfills vs. WTE) yields oxidation rates that typically approach 100 percent. Such hypothetical oxidation rates cannot be reconciled with the 10 percent oxidation rate that is the well established regulatory default value for oxidation. If such oxidation rates were valid, landfill methane collection systems would be unnecessary and serve no purpose. U.S. EPA's 10 percent oxidation rate is well supported in scientific literature. Significantly, the IPCC Guidelines' default value for oxidation of landfill methane is zero. If the methane oxidation rates yielded by the CALMIM model were valid, ARB's regulations for control of landfill methane would be completely unnecessary and an unlawful exercise of agency authority. The second of the two alternative (and contradictory) rationales that we understand was suggested by Board staff is the assumption that landfill methane collection systems will continue to operate for 260 years post-closure. If that were true, a significant portion of the landfill methane that ARB had previously recognized as being released to the atmosphere post-closure would instead be captured and controlled, and the relative GHG impact of landfills versus WTE would change accordingly. The 260-year assumption is, however, arbitrary in the extreme and contradicts reality. In that regard, U.S. EPA and ARB regulations allow landfill gas collection systems to shut down permanently if certain performance criteria are met. Additional regulations require landfill operators to provide funding (or alternative financial assurance) to satisfy post-closure maintenance obligations. These federal and State regulations address long-term, post-closure care of landfills, including methane collection systems, as well as reasonably foreseeable corrective actions. Nowhere do they contemplate a requirement for post-closure operation of methane collection systems for anything approaching 260 years. Nor is there any requirement that landfill operators set aside the massive amount of funding that would be necessary to satisfy such a daunting requirement. The absence of such requirements is quite understandable. They would have no justification, environmental or otherwise. Moreover, if such multi-century post-closure care and financial assurance requirements were to be established, landfill tipping fees would soar, with increases many times current levels. In sum, nothing in the administrative record supports ARB's changed position in which WTE facilities would be subject to the CO_2e allowance purchase requirement under the Board's proposed cap-and-trade regulations, and the result of such action will clearly be adverse for the environment, as explained in the comments the Coalition submitted to the Board last month (a copy of the Coalition's August 11 comment letter is attached). Accordingly, the Coalition respectfully submits that the regulations exclude WTE facilities from the proposed CO_2e allowance requirement. While the exclusion should, at a minimum, apply to California's existing WTE facilities, in the interest of achieving a significant future reduction in waste management sector GHG emissions in California, the same policy should also apply prospectively to new WTE capacity. (LGCRE3)

Comment: WM requests confirmation of the proper interpretation of section 95852.2(a)(7), Emissions without a Compliance Obligation, with respect municipal solid waste that is directly combusted or converted to a cleaner burning fuel. First, what is the definition of “cleaner burning fuel”? Cleaner than what? Further clarification is needed here to comply with the clarity standard of the California Administrative Procedure Act. Secondly, attorneys with whom we have consulted interpret the language to exempt from compliance MSW that is directly combusted or converted to cleaner-burning fuel regardless of its biogenic origin. The phrase, “including MSW directly combusted or converted to a cleaner-burning fuel” appears to be inclusive of all solid waste, regardless of biogenic or anthropogenic origin. If this is CARB’s intent, we concur. As we have repeatedly stated, a life-cycle assessment of WTE facilities clearly demonstrates an overall reduction in GHG emissions. The language you have modified in the 2nd 15-day comment period appears to embrace this concept, and WM certainly supports that there should be an exemption for the entire municipal solid waste stream that is beneficially converted to renewable energy. In the July draft of the regulations, CARB had reversed its recognition of WTE’s ability to lower GHGs. The discussion draft regulations initially proposed that the three existing WTE facilities operating in California would be excluded from a Cap and Trade compliance obligation. As we stated in our comments on the July draft, CARB’s reversal threatened these facilities’ operations and could significantly increase municipal costs of waste management, environmental impacts from truck traffic and distance to disposal, and GHG emissions. We strongly support exclusion from compliance obligations for all municipal waste that is converted into cleaner burning energy. This exclusion should be applied to all technologies, including conversion technologies that can demonstrate their ability to lessen the amount of greenhouse gas emissions into our atmosphere. (WM4)

Comment: CARB staff removed from the discussion draft of the 15-day amendments, released on July 8, 2011, language in section 95852.2 that excluded from compliance obligations, "Direct combustion of municipal solid waste with energy recovery in an existing permitted facility" because of concerns over lifecycle analysis assumptions that originally supported this exclusion. However, we believe these concerns to be unsupported. The uncertainty expressed by CARB focused on landfill methane surface emissions post-closure with no GCCS. CARB used two approaches to support their decision to reverse the exclusion. The first is based upon a hybrid model of gas generation to determine lifetime fugitive landfill emissions. Based upon our review and subsequent meetings, CARB appears to have backed off on the first approach because of demonstrated technical problems with the analysis. CARB' s second analysis utilizes a first order decay model to estimate how long it would take, post-closure, for landfill gas generation to reach a heat rate of three million BTUs per hour (MMBtu/hr). CARB has arbitrarily chosen this heat rate to define the time at which a landfill gas collection system could be turned off; approximately 260 years for the Puente Hills Landfill and 93 years for the Fink Road Landfill. CARB then plugged these new time estimates in a lifecycle analysis to conclude that landfilling produces less GHG emissions than combusting an equal amount of waste in a waste-to-energy facility. We have serious concerns with this approach. Methane collection systems do not operate and are not required or designed to operate for anything approaching 260 years and landfill operators are not required to set aside the funding that would be necessary to satisfy such a requirement. With so much regulatory focus on placing bounds on how long GCCS need to operate in the post-closure period, it is very clear that an analysis that would assume a full GCCS operating for a 260 year post-closure period is absurd, and not based in reality. More appropriate estimations of the time to tum off the GCCS Regulations couple a time-certain period with performance standards to define when a GCCS can be turned off. By using the CARB integrated surface standard of 25 ppm coupled with air dispersion modeling, a landfill gas generation model can be used to determine the approximate time into post-closure where the integrated surface levels will be no greater than 25 ppm (assuming no GCCS). The results of this analysis demonstrates that the Puente Hills Landfill will reach the 25 ppm integrated methane surface level in approximately 26 years post-closure, and the Fink Road Landfill in approximately 57 years. Both these estimates provide a more reasonable, and expected, time by which a GCCS can be turned off. In addition, these estimates mirror the assumptions used in the original lifecycle approach used by CARB, which is the basis for the original exclusion language. Finally, even these results should be viewed as conservative since, landfills would phase out portions of their GCCS prior to the 26 and 57 years determined for the Fink Road and Puente Hills Landfill, respectively. A more thorough analysis clearly demonstrates that when a suitable modeling approach is used to estimate when a GCCS will be removed, the resulting time frames fall within those contained in the original analysis on which CARB previously made its decision to exclude the existing waste-to-energy facilities. On this basis, we request the exclusion language be re-inserted in section 95852.2. (LASD5)

Comment: The 15-day modification discussion draft contained in section 95852.2, language that excluded from compliance obligations, "Direct combustion of municipal solid waste with energy recovery in an existing permitted facility.'" CCEEB requests that the language contained in the discussion draft be re-inserted in section 95852.2. The owner/operators of these facilities have previously demonstrated to the satisfaction of CARB staff that the existing waste-to-energy facilities cannot spread the cost of allowances to a consumer base; haulers would simply take the post-recycled waste to the cheaper option, landfills, resulting in much higher levels of GHG. The facilities would have no choice but to absorb the cost of the allowances creating a huge financial burden for already financially strapped local governments. CARB has presented two analyses justifying the removal of the waste-to-energy exclusion language, both of with have been demonstrated to be flawed technically. To date, nothing in the administrative record supports CARB's changed position. The fact remains that subjecting the existing waste-to-energy facilities to the proposed cap and trade regulations will have an adverse impact on the environment. Also, re-inserting the language is consistent with the resolution adopted at the 12/16/10 Board meeting requiring, "the Board determine and report back to the Board a mechanism to satisfy all the risk of emissions leakage and compliance obligations of existing municipal waste-to-energy facilities in the proposed cap-and-trade program." (CCEEB4)

Response: When the Board first considered the cap-and-trade regulation in December 2010, some stakeholders raised concerns about including waste-to-energy facilities in the regulation. In response to this concern, the Board directed ARB staff to investigate whether including waste-to-energy facilities in the cap would result in "leakage" of greenhouse gas emissions. Our analysis indicates that diversion of waste from waste-to-energy facilities to landfills would not increase greenhouse gas emissions. This is because of California's strict statewide and district regulations that require capture of methane emissions from landfills. Thus, we would not expect that including waste-to-energy facilities in the cap-and-trade program would increase greenhouse gas emissions.

There are also important policy reasons to include waste-to-energy facilities in the cap. The cap-and-trade program is designed to both place an enforceable and declining cap on greenhouse gas emissions and to send a price signal to encourage more efficient energy use. As part of this program, it is important to create a level playing field in order to send a consistent price signal. If we were to remove waste-to-energy facilities from the cap, it would inappropriately incentivize electricity generated by these facilities, since they would not be subject to the price signal. In addition, our partner in the Western Climate Initiative, British Columbia, is also planning to include waste-to-energy facilities as a covered sector in their cap-and-trade program.

We do recognize that the waste management system in California is complex, and that it is important to consider the broader picture of waste management, which includes landfills, waste-to-energy facilities, recycling, and composting, as well as reduction in the use of resources at the front end. Board Resolution 11-32 directs the Executive Officer to continue to work with Cal/Recycle and other stakeholders to characterize lifecycle emissions reduction opportunities for different options for handling solid waste, including recycling, remanufacturing of recovered materials in state, composting and anaerobic digestion, waste-to-energy facilities, landfilling, and the treatment of biomass. The Executive Officer shall identify and propose regulatory amendments, as appropriate, so that AB 32 implementation, including the cap-and-trade regulation, aligns with statewide waste management goals, provides equitable treatment to all sectors involved in waste handling, and considers the best available information. The Executive Officer shall report on progress in summer of 2012.

E-27. (multiple comments)
Comment: In October 2010, CARB released the proposed regulation for the cap and trade program. In a later meeting with CARB staff, the staff agreed to add language to section 95852.2, Emissions without a Compliance Obligation, under Fugitive and Process emissions, "CH_4 and N_2O from Municipal Wastewater Treatment Plants." The sheet with that change was introduced at the December 16, 2010 Board meeting where all the documents were approved by the Board, but the Resolution 10-42 required that Attachment B be subject to 15-day public review, and comments considered. The first 15-day package was release in July 2011. The language cited above was contained in

this package. To our knowledge, no negative comments were received addressing this specific language. Unfortunately, the second 15-day package released removed the language with no explanation. It is our opinion that if there were no negative comments from the first 15-day period, the above listed language should not have been removed from the document. We respectfully request correction of this oversight as part of the second round of review comments processing at this time. (CWCCG)

Comment: Streamlining the federal mandatory reporting program with the State program caused some unintended consequences. The federal program requires the estimation and reporting of fugitive CH_4 emissions from landfills. When the two programs were combined, this estimation now had the unintended effect of drawing landfills into the cap and trade program. In December 2010, staff introduced language in section 95852.2 excluding fugitive CH_4 from landfills. In the most recent 15-day package the language was removed from this section, but the exclusion was introduced into the State mandatory reporting regulation, as an exclusion of landfill reporting, from State reporting requirements, as defined in the specific section cited in the federal regulations. This in effect would currently exclude landfills from the cap and trade program, but not fully protect them into the future. Future changes in federal regulations could potentially cause this problem to re-occur. More importantly though, when CARB decided to regulate landfills under the Early Action Measures, it was with the understanding and full cooperation of the landfill industry, that this action was in place of including landfills in the cap and trade program. The landfill industry worked with CARB to promulgate the most stringent landfill regulation in the world on that basis. In the spirit of that understanding, landfills should receive a full exclusion from the cap and trade program. We therefore recommend that the original language, "CH_4 from landfills", be re-inserted back in section 95852.2 under fugitive and process emissions. This action would not only be consistent with the understanding reached when the Early Action Measures were adopted, but also avoids any unintended consequences of changes to federal mandatory reporting regulations. With similar concerns that future revisions to the federal mandatory reporting program could require reporting of fugitive/process CH_4 and N_2O emissions from municipal wastewater treatment plants, and inadvertently draw these facilities into the state cap and trade program, staff agreed to proactively include exclusion language in section 95852.2 for these emissions (language introduced during the December 2010 Board meeting). This action was prudent to avoid having to re-open the rule in the future. In conversations with staff questioning the removal of this language, they were unaware of the original purpose for including them. We therefore, recommend that the language "CH_4 and N_2O from Municipal Wastewater Treatment Plants." be re-inserted back in section 95852.2 under fugitive and process emissions. (LASD5)

Comment: The exemption from a compliance obligation for landfill fugitive emissions and wastewater treatment plants has been removed in revised sections 95852.2(b)(4) and (5). We are very concerned that deleting this language is contrary to our previous understanding these fugitive emissions would not incur a reporting obligation. While we are pleased that the CARB stated reason for this modification appears to recognize that there can't be a compliance obligation for emissions that will not be required to be reported, that does not remove the need to make sure it is clear that there is no compliance obligations for fugitive emissions from landfills and wastewater treatment plants. Restoring the deleted language provide necessary clarity in the regulations. With respect to landfill fugitive emissions, we specifically request that "Methane from Landfills" be added back into those fugitive emissions that are excluded from a compliance obligation in section 95852.2(b) for the following reasons:

- It is virtually impossible to accurately measure fugitive emissions from landfills. Unless revised, the proposed regulations may impose a compliance obligation on emissions that cannot be accurately measured imposing an untenable regulatory burden on our facilities.
- CARB has already included fugitive methane emissions from landfills in a discrete early action measure, the Landfill Methane Control Measure Regulations. These regulations require owners and operators of certain uncontrolled MSW landfills to install gas collection and control systems, and existing and newly installed gas and control systems to operate in an optimal manner. These regulations represent the most stringent landfill methane control regulations in the country and there is no reason to impose an additional compliance obligation for fugitive landfill emissions.
- These regulations should provide an incentive to maximize the capture and beneficial use of biomethane as a replacement for fossil fuel. As currently written, these draft regulations may well provide a disincentive through multiple compliance and reporting obligations. Similar arguments can be made for fugitive methane from waste water treatment plants. We ask that you restore the specific exemptions from a compliance obligation in section 95852(b) for "Methane from Landfills," and "CH_4 and N_2O from municipal wastewater treatment plants." (RSI)

Comment: WM is concerned that the exemption from a compliance obligation for landfill fugitive emissions and waste water treatment plants has been removed in revised sections 95852.2(b)(4) and (5). This omission is contrary to our previous understanding and discussions. The explanation given in the reasons for the modifications in the 2nd 15-day notice is found in an explanatory document. While we are pleased that CARB recognizes in its notation that there cannot be a compliance obligation for a source that is not required to report emissions, that recognition in a non-binding explanatory note to the regulation is insufficient to ensure that there is no compliance obligations for fugitive emissions from landfills and wastewater treatment plants. Failure to restore the deleted language will result in a lack of clarity in the regulations that is contrary to the California Administrative Procedure Act. With respect to landfill fugitive emissions, we specifically request that "Methane from Landfills" be added back into the listing of fugitive emissions that are excluded from a compliance obligation in section 95852.2(b) for the following reasons: It is widely acknowledged that there is no accurate method to measure fugitive landfill methane emissions and therefore it is against good public policy to impose a compliance obligation on a source whose emissions cannot be accurately measured. Inclusion of landfill fugitive emissions in the Cap and Trade regulation is duplicative and punitive. CARB has acted to regulate fugitive methane emissions from landfills in one of the Agency's first early action measures: (http://www.arb.ca.gov/cc/landfills/landfills.htm). Through this regulation, CARB has taken direct action to limit fugitive methane emissions to the lowest achievable level. These regulations represent the most stringent landfill methane control regulations in the world. CARB achieves nothing by leaving the regulatory door open for a Cap and Trade compliance obligation for fugitive landfill emissions for a source category that is already subject to a stringent command and control regulation under the same underlying statute (AB 32). Strong incentives are in place to maximize the capture and beneficial use of biomethane as a replacement for fossil fuel. CARB should recognize that there is strong economic and technological reason to capture fugitives as a fuel source and virtually no incentive to produce fugitive methane emissions and waste valuable renewable energy. Similar arguments can be made for fugitive methane from wastewater treatment plants. We ask that you restore the specific exemptions from a compliance obligation in section 95852(b) for: Methane (CH_4) from Landfills, and CH_4 and nitrous oxides (N_2O) from municipal wastewater treatment plants. (WM4)

> **Response:** CO_2 emissions from combustion of biomethane and biogas from landfills and wastewater treatment plants are exempt from having a compliance obligation. We modified the MRR to exclude reporting of fugitive emissions from farms, livestock operations, and landfills; thus, landfills are not covered under the cap-and-trade regulation.

Emissions Without a Compliance Obligation

E-28. Comment: Include a process to add to the list of fuels without a compliance obligation in section 95852.2. Modify section 95852.2 as follows:

> Emissions from the following source categories and from the combustion of the following fuel types count toward applicable reporting thresholds, as applicable in MRR, but do not count toward a covered entity's compliance obligation set forth in this article unless those emissions are reported as non-exempt biomass derived CO_2 under MRR. <u>The Executive Officer may add additional source categories meeting similar criteria.</u> Emissions without a compliance obligation include: (CCEEB4)

> **Response:** This comment falls outside the scope of the second 15-day changes to the regulation. No response is necessary.

Issuance of Compliance Instruments

E-29. Comment: In section 95820(c), there should be criteria on cause to terminate or limit authorization to emit. If not, then this provision should be deleted. Modify section 95820(c) as follows:

(c) Each compliance instrument issued by the Executive Officer represents a limited authorization to emit up to one metric ton in CO_2e of any greenhouse gas specified in section 95810, subject to all applicable limitations specified in this article. ~~No provision of this article may be construed to limit the authority of the Executive Officer to terminate or limit such authorization to emit.~~ A compliance instrument issued by the Executive Officer does not constitute property or a property right. (CCEEB4)

Response: This comment falls outside the scope of the second 15-day changes to the regulation, which included no modifications to section 95820(c). No response is necessary.

Carryover

E-30. Comment: ARB should fix the "buyer liability" issues with regard to offsets and allow carryover of the 8 percent compliance limit across years and compliance periods. Modify section 95854(b) as follows:

(b) The total number of compliance instruments identified in section 95854(a) that each covered entity may surrender to fulfill the entity's compliance ~~obligation for a compliance period~~ must conform to the following limit:

Oo/S must be less than or equal to Lo

In which:
Oo = Total number of compliance instruments identified in section 95854(a) submitted <u>since January 1, 2013</u> to fulfill the entity's <u>total</u> compliance obligation ~~for the compliance period~~ <u>through the current compliance year</u>.
S = Covered entity's <u>total</u> compliance obligation <u>beginning January 1, 2013 through the current compliance year</u>.
Lo = Quantitative usage limit on compliance instruments identified in section 95854(a), set at 0.08. (CCEEB4)

Response: This comment falls outside the scope of the second 15-day changes to the regulation, which included no modifications to section 95854(b). No response is necessary.

Miscellaneous

E-31. (multiple comments)
Comment: Per section 95850, an emission violation is based on the reports submitted by the verification body and reporting entity. We recommend that the regulation, to the extent possible, prohibit the execution of indemnification agreements between the program participants and the verification/reporting agencies. In order to establish a foothold in the program, it is foreseeable that reporting agencies might offer or facilities might demand, indemnification agreements which will provide that, in the event that a

violation is established through one of their repots, the reporting agency will bear the penalty. This will dilute the incentive for program participants to accurately report their emissions and may result in the concealment of information from the verification body. (SCAQMD5)

Comment: CCEEB recommends that the program allow compliance entities to hold, in holding accounts, sufficient allowances to cover their obligation for the entire compliance period based on a rolling three-year emissions obligation. This change would free up allowances for the major compliance entities and enable a much more liquid market where an entity could adequately hedge its forward risk without major complications. While there are still allowances locked in compliance accounts in some years, the increase in holding limits makes these limitations much more manageable. (CCEEB4)

Comment: Business fluctuations at the end of a compliance period are anticipated. These fluctuations could adversely impact the smooth operation of the market. CCEEB recommends that vintage allowances (i.e., borrowing from current year) be allowed to be used during the true-up period. This will provide a mechanism for the end of compliance truing-up that will increase market confidence. (CCEEB4)

Comment: Section 95814(b)(1) would prevent air districts from serving as a verification body or as an offset verifier from holding compliance instruments. This should be allowed for air districts, as holding a small amount of compliance instruments may be needed for insurance purposes for verification services. (SCAQMD5)

Comment: Section 95852 provides that suppliers of RBOB, distillate fuel oils, natural gas liquids, and blended fuels are required to account for allowances for combustion of these fuels by their downstream users and there is not a concern regarding double-regulation since the downstream users are not required to account for such allowances. In contrast, while natural gas suppliers are required to hold allowances that represent the natural gas that is used by downstream users who do not fall under the scheme, they are not required to hold allowances for entities that fall under the scheme (covered entities) since those covered entities will be required to hold such allowances. Our concern is that there will be (at best) confusion over this issue and (at worst) manipulation of this issue such that downstream users of natural gas who are covered entities will face both prices of natural gas that includes the cost for allowances (even though the provider does not have to obtain such allowances) while the covered entity must still obtain the allowances itself. We note that ARB added language at Section 95852(c)(3) such that ARB will provide to the natural gas suppliers a list of all their customers that are covered entities—including information on the aggregate natural gas volumes and emissions calculated from the supplier's natural delivered to the covered entity. This is a helpful addition in that it may help natural gas providers to understand which of their downstream users already have to pay for their allowances; however, it doesn't provide any mechanism for avoiding (or addressing) the situation in which the natural gas provider still embeds the cost of allowances into the sale price for the covered entity (resulting in double-payment). We continue to seek that ARB incorporate a mechanism to address this concern. Such a mechanism could include a requirement of transparency on the part of the natural gas provider along with a mechanism to discount the amount of allowances the downstream user is required to obtain in order to avoid a double payment. (UNITEDAIRLINES3)

Comment: Section 95852(c) of the Second 15-day Revisions recognizes that natural gas suppliers' compliance obligation will be reduced by the amount of natural gas supplied to an entity that already has a compliance obligation under the Cap-and-Trade Program, and properly includes that metric in the calculation of their overall obligation. However, there is still disconnect between this reduced compliance obligation for the natural gas supplier and the ability to track the fuel sold to compliance entities in forward markets. Because forward contracts for natural gas are transacted on electronic exchanges, there is no way to identify sales to covered entities in advance of completing the transaction. Accordingly, it is likely that natural gas suppliers will incorporate the cost of the GHG compliance obligation into the price of the natural gas contracts, since CARB computes the compliance obligation after the fact, rather than at the time of the sale. Because futures markets are going on even at this time—for fuel that will be sold during the second compliance period—there is a need to address this issue now, and not wait until the second compliance period. Without some direct means to track the contracts between buyers and sellers before the price of the gas is set, buyers of natural gas with a compliance obligation under the Cap-and-Trade Program will still face the prospect of paying twice for emissions associated with that gas. This is because the seller will not know at the time that the contract is entered into whether or not the buyer is a covered entity. Therefore, since the seller's compliance obligation will not be known at the time of the sale, they will need to include the potential compliance cost in the price of natural gas sold. In order to address this, NCPA recommends that CARB provide allowances to these covered entities in an amount equal to the amount of CO_2e of GHG emissions for natural gas delivered to covered entities to offset the emissions associated with the compliance obligation that will be borne by the covered entities for the delivered natural gas. This adjustment does not create any additional allowances, as the compliance obligation associated with the supply of natural gas will have increased by an equal amount to the covered entity's free allocation. This is the most efficient means by which to eliminate the potential for double charging the buyer (covered entity) for the carbon cost. NCPA urges CARB to address this issue now, and not wait until 2014. (NCPA4)

> **Response:** These comments present issues that ARB will continue to monitor during the implementation of the program. However, for the present purposes, they fall outside the scope of the second 15-day changes to the regulation. No further response is necessary.

E-32. Comment: The CCC recommends that the compliance obligation exemption in section 95852.2 be extended to State institutions such as universities and prisons. Where a third party CHP operator is supplying the thermal and/or retail electricity, then the compliance obligation for the emissions associated with the energy purchased by the host state entity should be exempted from the cap and trade regulation until the end of 2013. (CACC3)

> **Response:** We did not exempt large cogeneration facilities at universities and prisons from the compliance obligation. As directed by Board Resolution 11-32, the Executive Officer will work with State universities and stakeholders to identify options for how universities can comply with the regulation or propose rule amendments, as appropriate.

E-33. Comment: Section 95852(a)(1) describes the operators of facilities that have cap-and-trade compliance obligations and includes references to Petroleum and Natural Gas Systems. Section 95852(h) describes certain requirements for obligations from this sector, but also contains the language "except as specified in section 95852.2." In describing the compliance obligation for Petroleum and Natural Gas Systems in section 95852(a)(1), there is not provision or reference to section 95852.2. The same exception should also be included in section 95852(a)(1) to make it clear that compliance obligations are required, except as provided in 95852.2. We therefore recommend that the first sentence of section 95852(a)(1) be amended to include the phrase "except as specified in section 95852.2" at the end of the sentence. (PGE5)

> **Response:** We did not make the suggested changes. Section 95852.2 is entitled "Emissions without a Compliance Obligation." We believe this provides sufficient clarity to explain that these emissions do not count toward a covered entity's compliance obligation.

E-34. Comment: SMUD does not support, in general, allowing borrowing between compliance periods, as we believe this may result in a lack of balance between the amount of compliance instruments available in early years and the amount needed for compliance, in effect causing delays in investments that may be needed to achieve compliance by 2020. However, adverse circumstances, such as a two or three year sequence of low hydro years combined with more rapid than expected economic growth, could cause allowance prices to spike in the last year of a compliance period, and then fall as a new compliance period affords additional flexibility. This kind of price volatility will also cause delays and uncertainty in needed investments. SMUD believes that one indicator of such inter-compliance-period volatility is a significant price increase so that obligated entities substantially purchase allowances from the Allowance Price Containment Reserve. SMUD believes that a mechanism to react to this potential circumstance, and act to smooth long-term allowance prices in the transition between compliance periods would be beneficial to the market. Addressing this will also delay or prevent an unfortunate "run" on purchasing allowances from the Reserve, but making additional supply available in limited circumstances as suggested. Modify section 95856(b)(2) as follows:

> (2) To fulfill any compliance obligation, a compliance instrument must be issued from an allowance budget year within or before the year for which an annual

compliance obligation is calculated, or the last year of a compliance period for which a triennial obligation is calculated, unless:

(A) The allowance was purchased from the Allowance Price Containment Reserve pursuant to section 95913;

(B) The allowance is used to satisfy an excess emissions obligation; or

(C) The compliance instrument is from the allowance budget year following a triennial compliance period and 40% of the allowances in the Allowance Price Containment Reserve have been purchased for compliance during the compliance period. (SMUD4)

Response: We did not allow the type of borrowing that the commenter proposes. We believe we have provided sufficient flexibility to deal with issues such as low hydro years. The multi-year compliance periods are in place to help with year-to-year variability that may affect the emissions obligation.

F. CO-POLLUTANTS

F-1. Comment: The cumulative impacts of the proposed changes haven't been analyzed, especially in low-income communities of color. For example, Wilmington, California hosts many heavy polluting sectors. Consequently, the regulation's specific provisions that loosen standards for these polluters, and effectively subsidize these highly concentrated industries through free allocations and loose benchmarks, have a major potential to encourage further expansion and increase cumulative impacts. About a third of the entire State's oil refinery capacity is located in or next to Wilmington. The Wilmington oil field (about the third largest in the country) is also located here, as well as the most extreme goods movement and transportation sources in the State. The proposed changes actually encourage the worst polluters through subsidizing credits for the most intensive types of oil drilling. We urge CARB to evaluate the cumulative impacts of the regulation. (CBE3)

> **Response:** We disagree that the revised allocation would incentivize practices that would lead to an increase in co-pollutant emissions.
>
> Moreover, we evaluated the cumulative impacts of the proposed cap-and-trade regulation in Wilmington in Appendix P: Co-Pollutant Emissions Assessment in the *Staff Report: Initial Statement of Reasons.* The proposed changes will not modify the overall findings of the Emissions Assessment. Therefore, it is not necessary to reanalyze the impacts of the regulation. This regulation does not loosen standards for co-pollutants or alter or "loosen" in any way the existing national, state, and local rules and regulations for co-pollutant emissions. Any options chosen by facilities to meet the cap-and-trade requirements must be done in the context of existing air quality regulations. The cap and trade regulation will not affect the stringency of these programs and as such, they provide an additional mechanism to ensure continued air quality improvement.

G. DEFINITIONS

G-1. Comment: The new draft changes the definition for “permanent” to the detriment of the public, and to the environment. The lifetime of CO_2 is actually hundreds of years (clearly much longer than 100 years) for the bulk of CO_2 emissions, and essentially forever for about 25 percent. Redefining “permanent” to mean 100 years may seem effectively permanent compared to most regulatory contexts, but in this context, the opposite is true. CARB is fully aware that climate change is projected to be far worse in 100 years, even if California’s Cap and Trade were to be effective (an assumption we challenge). And with respect to the establishment of forests or to the impacts of CO_2 emissions, one hundred years is not long at all, and is definitely not permanent. The regulation change would essentially allow forests to be liquidated completely in 100 years, and any other offset would be allowed to be reversed at that time. It is understandable that CARB and offsets industry lobbyists would want to limit their responsibilities to a finite period of time, but the real need for actual permanent reductions illustrates the difficulty in enforcement of “permanent” offsets. If instead we directly replace polluting industries with a clean alternatives infrastructure, we don’t have to worry about overseeing out-of-state offsets programs forever or even for 100 years. (CBE3)

> **Response:** The definition for “permanent,” section 95802(a)(192) as it relates to offsets, was modified in response to issues raised during the first 15-day changes to the regulation to improve clarity. Since the estimated atmospheric lifetime of an anthropogenic CO_2 emission is far longer than any minimum offset project term currently being considered, we deleted that portion of the definition and focused on the issue important to the environmental integrity of ARB’s cap-and-trade program; that GHG reductions or removal enhancements are either not reversible or that mechanisms are in place to replace any reversed GHG emission reductions or removal enhancements. Sequestration projects are required to monitor and verify that any credited carbon remains sequestered for 100 years. This requirement is consistent with international standards.

Forest Owner Definitions

G-2. Comment: The definition of Forest Owner is too broad, as it includes many parties lacking control over timber management and land conversion. Requiring parties such as recreation and mineral right holders, as well as easement-holding non-profit land conservation groups, to take on liability for future reversals and invalidations for which they are not responsible, will prevent many projects from transitioning to ARB and reduce the supply of offsets to the compliance market. It also remains unclear in the definitions and body of the regulation, which specific forest owners bear responsibility for reversals and invalidations. We recommend the definition of Forest Owner be amended to “parties with ownership interest in timber holdings and control of harvest or conversion decisions,” both definitions add clarification that it is the forest Offset Project Operator that is responsible for intentional reversal and invalidation obligations under the regulation. (BLUESOURCE3)

Response: There are too many forest holders and carbon pools and sources involved in forest offset projects for ARB to make a determination of who is liable for activities that are undertaken on forest land. These kinds of liability issues must be worked out between the parties through third-party contractual agreements. From our perspective, we must ensure the enforceability of the regulation, and we believe the definition of Forest Owner with the regulatory provisions allows ARB to enforce against those parties that are responsible for reversals and invalidations.

G-3. Comment: CERP wants to bring the definition of "Forest Owner" (section 95802(a)(109)) to ARB's attention. CERP appreciates that ARB modified the definition of forest owner such that it does not include public parties who own conservation easements, but is unclear why the definition change was limited to public parties. CERP requests that ARB further modify the definition such that it also excludes private parties who hold conservation easements from liability. It does not make sense for private parties to be required to have liability for forest reversals if their only connection to the forest project is through a conservation easement. (CERP5)

Response: We clarified the definition in the forest protocol and in the regulation with respect to conservation easement holders. The definition states that a

> "Forest Owner is the owner of any interest in the real (as opposed to personal) property involved in a Forest Project, excluding government agency third party beneficiaries of conservation easement; and that Generally, a Forest Owner is the (owner in fee) of the real property involved in a Forest Project. In some cases, one entity may own the land while another entity may have an interest in the trees or the timber on the property, in which case all entities or individuals with interest in the real property are collectively considered Forest Owners, however, a single Forest Owner must be identified as the Offset Project Operator."

We believe this makes the exclusion of easement holders explicit. We also modified text where needed to ensure consistency in the term as defined in the protocol and the Regulation.

G-4. Comment: CARB has defined "Air Dried Ton of Paper" as paper with 6 percent moisture content (section 95802, page A-6). Since the industry definition for Air Dried Ton is 10 percent moisture content, the proposed definition should be changed to reflect the industry standard or be written based on "bone dry" or "oven dry" tons (both defined as 0 percent moisture content) to avoid potential inconsistencies with other reported production data generated by industry. (TI2)

Response: This comment was previously submitted under the first 15-day comments and was responded to under the 15-day changes to the regulation. Therefore, no additional response is required.

G-5. Comment: There appear to be inconsistencies between definitions in the MRR and the cap-and-trade second 15-day modifications. Unfortunately, many of the new definitions in the MRR were not added to the cap-and-trade regulation and in other cases the cap-and-trade definitions were not conformed to the new or revised MRR definitions. Due to limited time to review both regulations in detail, we are unable to provide a complete list of our concerns, but offer the following examples. We suggest that the MRR staff convene a conference call of affected parties to explain the proposed changes and ensure that they are consistent with other federal and state legislation, and ultimately are workable.

> (i) Definition of Cogeneration – should be the same in both regulations, and should not be inconsistent with federal legislation, e.g. the Public Utility Regulatory Policies Act (PURPA) and the Federal Power Act (FPA). The definition in the cap-and-trade regulation requires "onsite" generation, and in the MRR definition the word "onsite" is struck. Before we can provide constructive comment we need an explanation of why the requirement was added to both definitions and then in only one regulation was deleted.
> (ii) It is unclear why MRR Definitions (206), (207), and (209) have been inserted only in the MRR but omitted from the cap-and-trade regulation. These definitions could be helpful in addressing ambiguities in the cap and trade regulation associated with the use of the terms "on-site" and "off-site." (CACC3)

Comment: In addition to the fact that the California Public Utility Commission approves the natural gas specifications that utilities must deliver to their customers, it must be noted that requiring at least 90 percent methane by volume would narrow the number of sources that can apply a default value to emissions calculations but would serve no other relevant purpose in either the MRR or the Cap and Trade Regulation. In fact, the opposite would occur, causing natural gas users to conduct excessive analysis with insignificant results. SoCalGas and SDG&E request ARB exclude the 90 percent methane requirement from this rule pending further study of the effects and burden of this "enhanced" reporting requirement. The portion of section 95802(a)(197) "and which is at least ninety percent methane by volume," should be deleted. (SEMPRA4)

Comment: Use of the word "quality" in section 95802(a)(197) "Pipeline Quality Natural Gas" is used in the context of these regulations to define a default "range" for purposes of MRR calculations. While ARB has added the qualifier, "As used in this regulation," the word "quality" can be eliminated without changing meaning or function. The California Public Utility Commission (CPUC) approves the natural gas specifications that utilities must deliver to their customers. Since CPUC has authority over natural gas quality issues, ARB should choose a different term to define the "default range" for the calculations required under this regulation. Additionally, the word "quality" implies a standard or grade that has an intrinsic value, characteristic or features. In many cases the word "quality" is used to imply excellence or grade and implies a positive connotation wherein anything that is not "quality" creates a negative connotation. The use of the word "quality" may create a level of confusion among natural gas users because it could be construed as implying that gas that meets pipeline specifications is nevertheless not “pipeline quality.” The phrase “pipeline quality natural gas” should be modified throughout the regulation to state “pipeline natural gas.” (SEMPRA4)

Comment: Deleting the clause “does not include the holder of a conservation easement” from the definition of “Forest Owner” inadvertently and unilaterally exposes holders of conservation easements to the various liabilities imposed on Forest Owners in the Rules. We recommend that this exclusion be re-instated. (TCF3)

> **Response:** The above comments fall outside the scope of the second 15-day changes to the regulation, and therefore do not require a response.

H. ECONOMIC IMPACTS

H-1. (multiple comments)
Comment: Verallia's Madera facility is "directly affected by this rulemaking" understates the potential significance of CARB's proposed Cap and Trade Program because the program as set forth in the proposed regulations potentially threatens the plant's long-term ability to compete, particularly with the substantial capital investments which will be required at the plant between now and 2020. Further, as CARB Staff documented, the container glass sector as a whole has a "high risk" of leakage due to its high energy intensity and trade exposure. For a number of reasons, including the cost-sensitivity of the business and the already high cost of manufacturing in California, the "protections" in the proposed Cap and Trade Program intended to mitigate this "high risk" for container glass manufacturing currently fall well short of providing the necessary relief. Thus, despite the fact that shutting down bottle manufacturers in California will simply force the State's wine industry to import significant quantities of non-California produced domestic bottles by truck, rail or other mobile GHG sources, (or further increase the wine industry's growing reliance on imports of glass bottles from China and other locations that are today much less environmentally conscientious with respect to emissions such as GHGs), the currently proposed Cap and Trade Program threatens the continuing existence of the container glass sector in California, especially for already efficient operations like Madera. (SMITHS2)

Comment: Should the Cap and Trade program force container glass facilities such as Verallia's Madera facility to shut down, the need for bottles by California's wine industry would likely result in importing those bottles by truck from neighboring states or from overseas. Under this scenario, the bottles necessary to support California's wine industry would cost more (given the additional costs of transportation) and generate additional GHG emissions (given the additional tracking distances). At the same point, GHG emissions would be increased at the out-of-state / out of country (e.g., Chinese) manufacturing facility; resulting in a net global increase in GHG emissions should our Madera facility be forced to close due to CARB's rulemaking. These environmental detriments would come in addition to the very real costs associated with eliminating hundreds of existing jobs and loss of local tax revenues associated with a plant closure. Thus, in addition to the high risk of leakage documented by CARB staff for container glass facilities, there are additional negative consequences associated with the leakage given the fundamental need for bottles by the California wine industry. (SMITHS2)

> **Response**: For the purposes of transition assistance, and to prevent economic leakage, facilities in the glass sector will be receiving most of their allowances for free. Allocating the allowances for free using emissions efficiency benchmarks and production will reward companies that have already made investments in energy efficiency and carbon reductions, and will not penalize those that produce goods in California. The classification of the glass sector as "high-risk" ensures that the glass sector will receive a greater amount of leakage protection for a greater duration than other firms that are deemed to be at less risk of economic leakage, therefore providing more protection for this industry.

Furthermore, in Resolution 11-32, the Board directed the Executive Officer to continue to review information concerning the emissions intensity, trade exposure, and in-state competition of industries in California, and to recommend to the Board changes to the leakage risk determinations, if needed, prior to the initial allocation of allowances for the first or second compliance period, as appropriate, for industries identified in Table 8-1 of the cap-and-trade regulation, including glass manufacturers.

H-2. Comment: Imposing a 10 percent tax on business via CARB's haircut proposal does nothing to 'maximize the environmental benefits' requirement under AB 32, and it is not needed to ensure the stringency of the overall cap—emission reductions will still be achieved by the 2020 goal. The tax proposed by CARB contradicts the AB 32 requirements of 'minimizing costs' and 'maximizing benefits' for California's economy in the design of emission reduction measures. The tax will negatively affect all California businesses, in addition to the anticipated fuel, energy and other cost increases that will be passed down to businesses from upstream providers. Ultimately, as California's economy suffers so too will employment, as an impact on business means an impact on jobs. Employers will be forced to reduce productions or lay off employees as the cost of compliance will make California less competitive with out-of-state businesses. With a 12 percent unemployment rate it is irresponsible to ignore the adverse economic impacts of the haircut by continuing to move forward with this egregious tax proposal. (CALCHAMBER4)

Response: The comment is unclear, but we understand it to mean that they are conflating the stringency of the benchmarks with the imposition of a 10 percent tax on business. This would not be a correct interpretation of the benchmark. In all of the industrial sectors there is at least one producer that we expect will receive nearly 100 percent of their allowances for free at the outset of the program. In fact, all facilities will receive the bulk of their allowances for free in the first compliance period, and many will receive the bulk of their allowances for free in the second compliance period.

Less-efficient industrial facilities will have to purchase some allowances, with the amount they have to purchase dependent on their efficiency relative to the benchmark. An average facility will have to purchase about 10 percent of their allowances, while the most efficient will need few, if any, additional allowances after allocation through the first compliance period where the assistance factor is 100 percent for all sectors.

The cap-and-trade program has been designed to reduce the potential for emissions leakage by providing a significant number of allowances for free. Allocating the allowances for free using emissions efficiency benchmarks will reward companies that have already made investments in energy efficiency and carbon reductions, and will not penalize all of those that produce goods in California. We believe that the program should reward only the most efficient facilities, while simultaneously minimizing the potential for leakage among all producers, including the less-efficient facilities. The stringency of the benchmark ensures this outcome.

H-3. Comment: Based on the proposed changes, cap and trade may result in the selling of the same kind of derivatives and futures which in other circumstances caused the major crash of the last few years. In 2009 when the U.S. considered a national cap and trade system, numerous financial and government experts highlighted that cap and trade could mean a massive futures commodity market. Due to the vast size of this new market, it could endanger our precarious economy. (CBE3)

Response: The comment falls outside of the second 15-day changes to the regulation. The provisions in the second 15-day changes to the regulation will have no effect on the development of a futures market because ARB has no control over whether a futures market develops. In fact, an independent futures market for California allowances (not operated by ARB) has been in existence since the adoption of the regulation in 2010, even though our cap-and-trade program is not yet in operation, and we have yet to issue a single allowance. Futures markets provide a useful service by allowing entities to reduce risk by entering into agreements that let them buy or sell allowances at a future date at a guaranteed price. We will retain the services of an independent market monitor to monitor the secondary market.

H-4. Comment: The proposed cap-and-trade regulations are effectively a direct tax on our operations, products and customers. The provisions are not fuel-neutral and place in-state refining operations at a disadvantage relative to other international operations and other energy supplies such as electricity. These higher costs will be felt by all energy-intensive businesses and will ultimately be borne by the citizens of the State in higher costs for goods and services. (CONOCO3)

Response: The comment falls outside of the second 15-day changes to the regulation. However, we recognize that there will be price increases from the cap-and-trade program. We do not believe that these price changes will result in large negative impacts to the state economy. Table N-3 and Table N-7 of the Staff Report highlight estimated changes in energy prices and resulting economy-wide estimates of impact. The estimated impacts show relatively small changes in economic growth and employment when compared to growth otherwise expected over 2007 to 2020. Please see Chapter VIII and Appendix N of the Staff Report for additional information about our economic analysis of the cap-and-trade regulation.

The comment also appears to conflate the stringency of the benchmarks with the imposition of a 10 percent tax on business. This would not be a correct interpretation of the benchmark. In all of the industrial sectors there is at least one producer that we expect will receive nearly 100 percent of their allowances for free at the outset of the program. In fact, all facilities will receive the bulk of their allowances for free in the first compliance period, and many will receive the bulk of their allowances for free in the second compliance period.

Less-efficient industrial facilities will have to purchase some allowances, with the amount they have to purchase dependent on their efficiency relative to the benchmark. An average facility will have to purchase about 10 percent of their allowances, while the most efficient will need few, if any, additional allowances after allocation through the first compliance period where the assistance factor is 100 percent for all sectors.

The cap-and-trade program has been designed to reduce the potential for emissions leakage by providing a significant number of allowances for free. Allocating the allowances for free using emissions efficiency benchmarks will reward companies that have already made investments in energy efficiency and carbon reductions, and will not penalize all of those that produce goods in California. We believe that the program should reward only the most efficient facilities, while simultaneously minimizing the potential for leakage among all producers, including the less-efficient facilities. The stringency of the benchmark ensures this outcome.

I. ELECTRICITY

Imported Electricity: Section 95852(b) and Related Definitions

Support of Modifications to Imported Electricity Provisions

I-1. (multiple comments)
Comment: PG&E appreciates a number of the modifications reflected in the latest version of the proposed regulation, to include: accounting for the greenhouse gas reduction value of out-of-state Renewable Portfolio Standard (RPS) eligible resources; providing increased flexibility for the surrender of allowances within a compliance period; and deferring to the California Public Utilities Commission to determine the manner in which consignment auction proceeds are returned to investor-owned utility customers. PG&E would also like to thank ARB for continuing to recognize the need to design allowance allocation and the use of auction proceeds for the benefit of utility customers. Finally, PG&E supports ARB's decision to defer the start of the cap-and-trade compliance obligation until 2013 to allow necessary market simulations and testing of auction systems, design and protocols in the first half of 2012. (PGE5)

Comment: The Utilities support the clarifying changes to the definition of "Qualified Export" in section 95802(a)(225); the removal of the definition for "Replacement electricity" in section 95802(a)(237); and the removal of Subsections (A) and (B) from the definition for "Resource Shuffling." The Utilities agree that an intentional act to commit resource shuffling purely to game the cap-and-trade market and avoid an emissions obligation should be discouraged. However, there are numerous provisions in California statute that either prohibit the delivery of high emitting GHG resources (SB 1368) or encourage the delivery of zero emitting GHG resources (SBx1 2), leaving it unnecessary to include Subsections (A) and (B). (MID4)

> **Response:** We thank the utilities for their support of the second 15-day changes to the regulation.

Electricity Importer Definition

I-2. (multiple comments)
Comment: The Proposed Changes amend the definition of "electricity importer" (section 95802(a)(87), p. 18) to remove the requirement for the electricity importer to be the entity that holds title to the electricity that it imports into California. Similar changes are made to other definitions. In some cases these changes will result in a different entity becoming liable for emissions associated with the imported electricity. SCPPA supports LADWP's comments regarding those changes. The new point of liability for imported electricity does not conform to the method by which allowances have been allocated between utilities. As a consequence, one utility may need to transfer allocated allowances to a second utility (or otherwise compensate the second utility) to cover the compliance obligation for emissions associated with electricity owned by the first utility but imported by the second utility. The Second 15-Day Change Notice does not

sufficiently explain the rationale for these changes, and stakeholders have not been given an adequate opportunity to discuss these changes with ARB staff in full. For these reasons and the reasons presented more fully by LADWP, these changes should be reconsidered, or an opportunity for further review of these provisions should be provided in 2012. (SCPPA8)

Comment: LADWP is seeking clarification from ARB regarding the modified definition for “Electricity Importers” in section 95802(a)(87) for facilities located outside the State of California with the first point of interconnection to a California balancing authority's transmission and distribution system. It is unclear that the out-of-state facility would fall under the jurisdiction of California, so the facility operator would not be an appropriate point of regulation. Additionally, it is unclear if this new amendment is intended to address electricity imports that do not cross a balancing authority boundary and therefore do not necessarily generate a NERC E-tag. (LADWP5)

Comment: The cap-and-trade definitions for “electricity importer” were substantially revised in the September 12, 2011 version of the cap-and-trade regulation. The definition provides that the importer is the purchasing and selling entity (PSE) on the physical path where the delivery point is in California [section 95802(a)(87)]. IEP remains concerned that there are instances when the PSE on the e-tag does not correctly identify the entity that owns power as it crosses the State’s borders. Moreover, the definition no longer refers to having “title” to the power or that the downstream entity will be the importer when CARB does not have jurisdiction over the seller. These additional changes make application of the definition to real-world power transactions far less clear. IEP believes that these provisions require further revision to specifically address circumstances when e-tags do not accurately reflect the title to power as it crosses the California border. This issue should be explicitly recognized by the Board as an area that will be addressed in a subsequent rulemaking prior to the start of the cap-and-trade program. (IEPA3)

Comment: Under CARB’s September 12, 2011 Proposed Amendments to the Regulation, the definition of “Electricity Importer” was revised such that the importer is the Purchasing Selling Entity (PSE) on the physical path where the delivery point is in the state of California. Iberdrola Renewables reiterates its concern that the PSE on the e-Tag may not correctly identify the entity that owns the power as it crosses the state border. In the previous version of CARB’s regulation, the definition of Electricity Importer included a requirement that the entity holding title to the power as it crossed the state border incurred the compliance obligation for the transaction. Although the accurate demonstration of the entity holding title would have been complicated, this previous structure was much more legally defensible. The current regulation creates uncertainty around import transactions and is likely to subject CARB to significant legal challenge if implemented. The Board should explicitly recognize this important issue as one requiring subsequent rulemaking prior to the final cap and trade program implementation. (IBERDROLA2)

Response: Many stakeholders objected to the use of the word “title” in the definition of “Electricity importer” included in the first 15-day changes to the regulation. We agree and removed the reference to “title”, and the definitions of “electricity importer,” “purchasing-selling entity,” and “marketer” were modified to clarify that delivery to the grid, not title, is the critical determinant of responsibility. ARB must rely on a clearly identifiable and verifiable entity that delivers electricity into California. Which party holds title to electricity may become a matter of dispute between counterparties and does not provide the certainty needed.

SCPPA8 believes that the removal of the word “title” means that “the new point of liability for imported electricity does not conform to the method by which allowances have been allocated…” but agrees that entities would be able to compensate each other as a result of their electricity transactions. We disagree, and clarify that removing the word “title” from the definition of electricity importer does not change the point of regulation, which has been and remains the first deliverer. Because this has consistently been the point of regulation, the allocation methodology remains consistent with this methodology. POUs are offered flexibility in compliance with this regulation, including consignment allowances at auction and transferring allowances to a Joint Powers Agency with which they have an agreement, as specified in the regulation. We recommend that these entities take steps to ensure that they compensate each other appropriately.

LADWP is concerned that entities with a first point of interconnection to a California balancing authority (BA) system might not be subject to California jurisdiction. The regulation states that the electricity importer is “the facility operator or scheduling coordinator”. If the out of state facility is connected directly to a California BA, the facility can both sell and schedule the electricity into California, in which case they are the importer. Alternatively, the facility desiring to sell electricity for import to California can find an SC that is willing to be the first deliverer and pay the compliance obligation.

In response to IEPA3 and Iberdrola, we note that we have consistently taken the approach that the first deliverer is responsible for compliance obligation. We do not rely on e-Tag information to establish the entity holding title to the electricity. We recognize that there are times when a covered entity has contracted with another entity to schedule the delivery of electricity. That Scheduling Coordinator will be listed on the e-Tag as the PSE. The PSE will have the obligation and will need to include the cost of compliance in their contract with the covered entity. Determining the entity that holds title would only add uncertainty for regulated entities, because such determinations for each transaction could be subject to dispute and may be documented in less accessible and reliable forms than e-Tags. The regulation is intended to provide the certainty which commenters have requested by specifying a straightforward mechanism such as e-Tag data that ARB will use to determine whether an entity is a first deliverer.

I-3. Comment: The changed definition of electricity importer provides that "For facilities physically located outside the state of California with the first point of interconnection to a California balancing authority's transmission and distribution system, the importer is the facility operator or scheduling coordinator." This definition disregards the role of a scheduling coordinator (SC) and imposes an obligation where none exists. A SC simply provides a communication service between the facility operator and the California Independent System Operator. It has a contract to perform scheduling and settlement services and is merely a conduit of dollars between the generator and the ISO; the SC does not have a mechanism to recover carbon costs. Only the facility operator should be considered the sole importer for out-of-state facilities that are directly connected to a California balancing area authority. The facility operator performs under an ISO participating generator agreement, and is an ISO dispatchable resource; it should be treated no differently than any other in-state resource. Modify section 95802(a)(87) as follows:

(87) "Electricity importers" are marketers and retail providers that deliver imported electricity. For electricity delivered between balancing authority areas, the electricity importer is identified on the NERC E-tag as the purchasing-selling entity (PSE) on the last segment of the tag's physical path, with the point of receipt located outside the state of California and the point of delivery located inside the state of California. For facilities physically located outside the state of California with the first point of interconnection to a California balancing authority's transmission and distribution system, the importer is the facility operator ~~or scheduling coordinator~~. Federal and state agencies are subject to the regulatory authority of ARB under this article, and include Western Area Power Administration (WAPA), Bonneville Power Administration (BPA) and California Department of Water Resources (DWR). (SHELLENERGY2)

Response: We do not agree with the modification suggested by Shell. The definition for “electricity importer” applies to deliveries that cross balancing authorities, and to deliveries that do not cross balancing authorities. The compliance obligation for imported electricity falls on the first deliverer. Not all electricity is delivered through the transmission system operated by the CAISO, and CAISO does not own a transmission system, but instead operates it on behalf of the owning entities.

Imported electricity not delivered to the transmission system operated by CAISO can be delivered with a first point of interconnection to another California BA transmission or distribution system. The other BAs in California are publicly owned utilities that own and operate their own transmission and distribution systems.

When a facility is directly connected to a California POU’s BA, it may or may not be the first deliverer. If not, it may be outside the jurisdiction of California. Therefore, we cannot place the compliance obligation upon the facility only. When the facility is not the first deliverer, the electricity is delivered by an importer, identified as the PSE on a NERC e-Tag. The PSE could also be the

Scheduling Coordinator (SC). The SC is defined in FERC-approved reliability rules. Purchasing-selling entities are designated on NERC e-Tags for each segment of the physical transmission path, which provides the means for reporting entities to clearly identify the quantities of electricity they import, export, and wheel across the California border. Market participants bidding into the CAISO markets are required to document electricity deliveries via NERC e-Tags, pursuant to CAISO Tariff section 4.5. Determining which transactions are specified or unspecified relies on written power contracts (and supporting records), settlement data, and invoices.

Shell states that a SC "has a contract to perform scheduling and settlement services and is merely a conduit of dollars between the generator and the ISO; the SC does not have a mechanism to recover carbon costs." We agree that the SC has a contract for these services. We identify the SC in these direct delivery cases with first point of interconnection to a California BA because the SC must have a contract to perform scheduling and settlement services and to be a conduit of dollars for the entity that owns the electricity that the SC schedules. Once the cap is in place, settlement will need to include the compliance obligation costs.

We note that the SC may be the agent of a facility, or of a California utility. In general, SCs are agents empowered by entities selling electricity into California (or elsewhere) to bind their counterparties to transactions like delivering electricity and making or taking payment.

In sum, it is appropriate to apply the compliance obligation in these certain, but limited, cases to the "facility or scheduling coordinator" because either of these may be the first deliverer. Once the cap is in place, to protect their interest, SCs will need to ensure that their agency agreements empower them to pay and be reimbursed for compliance obligation, as well as other current costs required to settle the delivery of electricity into California.

Other Definitions

Definition of EDU

I-5. (multiple comments)
Comment: The amendments to the definition of "electrical distribution utility" are broad enough to unintentionally include electric generators. The amendments made in the September version of the Cap and Trade regulation defines electrical distribution utility (EDU) as an "entity that owns and/or operates an electrical distribution system…" [section 95802(a)(85)]. While IEP does not believe that it is CARB's intent to incorporate electric generators into the definition of "Electrical Distribution Utility," the proposed amendments to this definition would include anyone that owns and or operates a gen-tie for purposes of generation interconnection (i.e. an electric generator). In order to remedy this effect, IEP recommends returning to the specific

language that was previously drafted in the July 2011 version of the cap and trade regulations, or alternatively creating a more narrow definition that would not capture individual generators, but that would solely speak to IOUs, publicly owned utilities and electrical cooperatives. (IEPA3)

Comment: Remove the added language in proposed section 95802(a)(85) defining an Electrical Distribution Utility as an “entity that owns or operates a distribution system” because it is not reasonably necessary to effectuate the purpose of the statute. This definitional change is incorrect and not reasonably necessary to effectuate the purpose of the statute. Owning or operating an electric distribution system is not the touchstone for having the ability to pass allowance value onto ratepayers. As ARB staff correctly stated in Appendix A, having a direct transactional relationship between the entity providing “public utility” services and the retail ratepayer is the proper test. The original definition for an EDU in the First 15-Day Modifications provided sufficient clarity and was consistent both with the language of AB 32 and the Air Board’s direction in Resolution 10-42. Several types of public entities are authorized to provide electric service to end-users. There is no requirement that these entities actually own or operate a distribution system in order to purchase electricity at wholesale, establish retail rates, and sell the electricity to end-use customers. The respective governing boards and/or councils of each entity type serves as the local regulatory authority (LRA) in regard to electricity rate-setting. These LRA’s are authorized by law to make all the decisions that would affect low-income consumers, as well as the entity’s investments in energy efficiency and renewable power. Public Utilities Code sections 224.3, 10001, and 11509; and Water Code section 22120 make clear that each LRA’s decisions are authorized by law without regard to whether the respective entity owns or operates a distribution system. In order to achieve the statutory purposes for distributing allowances to the electric sector, the phrase “entity that owns or operates a distribution system” should be removed from section 95802(a)(85) in the Second 15-Day Modifications. This language is neither consistent with the statute nor reasonably necessary to effectuate the purpose of the statute. (BBM)

> **Response:** It is not our intent to capture generators in this definition. We worked closely with the CPUC to refer to the CPUC code most applicable to IOUs and POUs that will receive allowances pursuant to section 95892. The recent change to the definition was intended to clarify that we do not want to pull in water utilities. Some water utilities are also under the jurisdiction of some of the POUs identified in Table 9-3. In addition, the design of our program is intended for allowance allocation to utilities that have a direct relationship with the end-user. Not all water purveyors in California have a direct relationship with an end-user of the water.
>
> We do not believe that a gen-tie is an electrical distribution system. In the electricity sector, a distinction is made between generation, transmission, and distribution. Distribution systems provide distribution-level transport of electricity and the electricity commodity. We are not aware of any generators that operate distribution systems that would qualify them as EDUs, although we are aware

that some generators sell electricity, essentially wholesale, “over-the-fence” without connecting to the utility grids. This type of activity is not included in the meaning of EDU, because the generator is not a utility.

Definition of Marketer

I-6. Comment: Marketers should be treated as any other PSE that imports electricity. The definition of "marketer" in section 95802(a)(159) does not accurately reflect the standard use of the term in wholesale electricity markets. A retail provider can also be a marketer and elect to purchase or sell electricity on the wholesale market. A marketer may also hold title to the power and be listed as the PSE on the market segment (market path) that tracks title and responsibility on a NERC E-tag, but may not be listed as a PSE on the physical path which would reflect a movement of energy. As amended, it appears that marketers may avoid the point of regulation for electricity imports that they own. (LADWP5)

Response: We agree that a retail provider can engage in purchasing and selling electricity like a marketer. However, the regulation needed to distinguish between retail providers and marketers that do not provide retail electricity to load in California. If a marketer delivers electricity to a first point of delivery (FPOD) in California, the marketer will directly or indirectly face the compliance obligation. To sell or deliver into California, a marketer or a retail provider may use an agent to accomplish the delivery across the state line, as discussed in responses above. It is common for electricity owners to authorize SCs to schedule and deliver electricity. We believe that an SC would be unwilling to deliver electricity and pay the compliance obligation without reimbursement or some kind of compensation from the owner/seller of the electricity for compliance costs.

Definition of Unspecified Source

I-7. Comment: The defined terms of “Unspecified Source of Electricity” or “Unspecified Source” appear in both the MRR and Cap-and-Trade regulations in section 95102(a)(399) and section 95802(a)(279), respectively, and are used throughout each regulation. Because the two sets of regulations together form the requirements of the reporting entities, the defined terms in the respective regulations need to be identical for reporting entities to consistently comply with the regulations. In addition, PG&E has revised the definition to further clarify that an unspecified source will have no reference to any specific generation facility or unit in the transaction and that the treatment of electricity as unspecified cannot be contradicted by subsequent information. Modify sections 95102(a)(399) and 95802(a)(279) as follows:

“Unspecified source of electricity” or “unspecified source” means electricity procured and delivered without ~~limitation~~ reference ~~at the time of transaction~~ to a specific facility’s or unit’s generation at the time of transaction, regardless of the specification in the corresponding NERC E-Tag, settlements data, or any other applicable information. Unspecified sources contribute to the bulk system power pool and typically are dispatchable, marginal resources that do not serve baseload. (PGE5)

> **Response:** While in general we agree that consistency in definition between the MRR and this regulation is beneficial, it is not necessary in all cases, and in some cases is inadvisable because the regulations have different purposes. We do not agree with the change suggested by PG&E. The suggested language would limit the ability to tie the delivery to a specific facility if there was evidence as displayed on the e-Tag, settlement data, or other information.

Compliance Obligation for Electricity

I-8. Comment: Iberdrola Renewables understands that CARB has relied upon electricity importers to “self-report” emissions under its existing GHG reporting program. Captured entities have been required to report all import transactions, engage a certified CARB verifying entity to verify its annual reports, and pay significant charges for all non-specified import transactions. It appears numerous importing entities have not been participating in the existing CARB reporting program and it is unclear how the CARB will ensure these entities are appropriately captured when the cap and trade compliance obligations are implemented. Failure to properly capture all electricity importers will significantly disadvantage entities subject to the cap and trade regulations. Iberdrola Renewables requests CARB clarify its efforts to ensure comprehensive capture of all entities importing electricity into the State of California. (IBERDROLA2)

> **Response:** This comment falls outside of the second 15-day changes to the regulation and addresses the MRR. However, ARB maintains the right to review data, when the entity does not report, and enforce penalties. The cap-and-trade regulation clearly states whom ARB recognizes as the first deliverer of electricity, and it is consistent with the amended MRR. For most electricity imported into California, including the market bids that are awarded by CAISO, delivery is documented on NERC e-Tags, and the purchasing-selling entity is clearly identified. ARB will rely on a variety of data sources.

I-9. (multiple comments)
Comment: NCPA supports the revisions to section 95852(b)(1) that adds the entire calculation for determining a compliance obligation of first deliverers in the Regulation, rather than references to the Mandatory Reporting Regulation (MRR). Including the relevant information and calculation within the Cap-and-Trade Program Regulation avoids confusion and the potential for miscalculations by removing the need to continually cross-reference the two regulations. (NCPA4)

Comment: The Utilities support the changes to section 95852(b)(1), which are needed to avoid confusion with the MRR. (MID4)

Comment: The compliance obligation calculation for electricity generators should refer only to the relevant section of the MRR. Section 95852(b)(1)(A), setting out the compliance obligation for operators of electricity generating facilities in California, refers generally to "all emissions reported and verified or assigned pursuant to MRR." This is too broad. Particularly for SCPPA members and other POUs, first deliverers that are operators of California generating facilities may also be electricity importers and report under both sections 95111 and 95112 of the MRR. Not all data reported under section 95111 of the MRR will result in a compliance obligation, so it is incorrect to state that all emissions reported under the MRR by a utility that operates a generating station count towards that utility's compliance obligation. Section 95852(b)(1)(A) should be revised to clarify that the compliance obligation for operators of electricity generating facilities in California is based on emissions reported under section 95112 of the MRR only. This change can be made without further 15-day public comment, as it is "nonsubstantial or solely grammatical in nature" for the purposes of section 11346.8(c) of the Government Code. Modify section 95852(b)(1)(A) as follows:

> (A) For first deliverers that are operators of an electricity generating facility in California, the calculation for compliance obligation includes all emissions reported and verified or assigned pursuant to MRR section 95112, except emissions without a compliance obligation pursuant to section 95852.2.
> (MID4)

Comment: The compliance obligation calculation for electricity importers should include more specific cross-references. The formula in section 95852(b)(1)(B) (p. 89) is of crucial importance to electricity importers and should be made as clear as possible. To this end, more accurate cross-references to the relevant sections of the Regulation and the MRR should be included. For example, the definition of "$CO_2e_{\text{specified}}$" refers generally to meeting the requirements of section 95111 of the MRR. Not all requirements set out in section 95111 relate to specified sources. To avoid confusion, only the relevant subsections of section 95111 should be referenced. (This comment also applies to the other references to section 95111 in section 95852(b)(1)(B)). In addition to section 95111 of the MRR, requirements for specified sources are also set out in section 95852(b)(3) of the Regulation. For completeness, section 95852(b)(3) should also be referenced in the definition of "$CO_2e_{\text{specified.}}$" These changes can be made without further 15-day public comment, as they are "nonsubstantial or solely grammatical in nature" for the purposes of section 11346.8(c) of the Government Code. Modify section 95852(b)(1)(B) as follows:

(B) For first deliverers that are electricity importers, emissions with a compliance obligation are calculated using the following equation:

$CO_2e_{\text{unspecified}}$ = Annual metric tons of CO_2e from imported electricity from unspecified sources calculated pursuant to MRR section 95111(b)(1).
$CO_2e_{\text{specified}}$ = Annual metric tons of CO_2e from imported electricity from specified sources that meet the requirements of section 95852(b)(3) and MRR sections 95111(a)(4), (b)(2) and (g).

$CO_2e_{\text{specified-not covered}}$ = Annual metric tons of CO_2e without a compliance obligation pursuant to section 95852.2 from specified sources that meet the requirements in MRR section 95111(g).
$CO_2e_{\text{RPS\_adjustment}}$ = Annual metric tons of CO_2e calculated pursuant to MRR section 95111(b)(5) that meet the requirements of section 95852(b)(4).
$CO_2e_{\text{QE\_adjustment}}$ = Annual metric tons of CO_2e from qualified exports reported pursuant to MRR section 95111(a)(6) that meet the requirements of section 95852(b)(5).
(SCPPA8)

> **Response:** We appreciate the support of NCPA and the utilities that submitted the MID4 comment letter, and we understand their support to mean that they find section 95852(b)(1) sufficiently clear. We do not agree with the modification suggested by SCPPA8 because we believe that it is clear that section 95852(b)(1)(A) refers to the emissions reported by first deliverers as operators of one or more generating facilities in California. We use this section to separately state the compliance obligation for emissions reported by a California electricity generating facility and those reported, in 95852(b)(1)(A), by an electricity importer. We agree with SCPAA8 that some first deliverers do both kinds of reporting. However, they must report separately as electricity importers from their reporting for facilities they own. We do not agree with the suggested modifications made by SCPPA8 to section 95852(b)(1)(B), because they are unnecessary. We agree with SCPPA that not all requirements in section 95111 relate to specified sources. However, reporters need only meet the requirements that apply for each category. Furthermore, it is possible that the specific paragraphs that SCPPA would like us to refer to will be modified in future rulemakings. By referring to the whole section, we can avoid the unnecessary cost and confusion that would result from modifying this regulation because a section of the MRR is renumbered.

Specified Sources

I-10. Comment: LADWP is concerned that for some specified sources of imported electricity, the amendments that are being proposed may result in these imports being incorrectly assigned default emissions under circumstances where the first deliverer that is scheduling the power into California on behalf of another party assumes responsibility as the first deliverer, and therefore must also include such imports as part of their MRR report. However, the entity scheduling the power under this scenario cannot demonstrate ownership in the facility or a written power contract for that electricity. This could have the potential unintended consequence of assigning default emissions to non-emitting specified imports (renewables, nuclear and hydro) that are currently reported based on ownership or contract rights. For example, a transmission outage occurs and the owner of electricity from a nuclear or hydroelectric generating facility must make arrangements to have that power imported through another transmission path by another entity that has transmission rights, but does not hold title to the power. Under this scenario, the regulation would assign default emissions to that zero-emission electricity for no other reason than the entity scheduling the power does not own the power. This outcome is unreasonable and does not accommodate commonly occurring situations related to specified imports. To add more complexity to this, the entity that schedules this zero-emitting power into California that is now assigned default emissions must also surrender allowances on behalf of the party that holds title to the power. This outcome is unreasonable and should be avoided. A separate issue of transparency also arises when the first deliverer of renewable energy is not also the entity owning the power. For example, LADWP schedules electricity imports into California from the Milford Wind Project in Utah on behalf of other SCPPA entities. Rather than correctly reporting the zero emission attribute in the MRR report of the entity that owns the electricity, the regulation requires that the first deliverer (i.e. LADWP) report the zero-emission renewable energy on LADWP's MRR report. This inappropriately distorts the emissions profile of the affected parties. (LADWP5)

> **Response:** Under the MRR, we require retail providers to report power imports to serve their own load. This means that even if LADWP is importing power for another utility, the other utility must also report, but has no obligation under the cap-and-trade regulation. Since we will have these data, if there are emergency situations as described above by LADWP where transmission could go down, we will have the ability to work with the entity with the obligation to match the reported data within that hour and will work with the covered entity on an appropriate emission factor.

I-11. Comment: CARB should harmonize its proposed regulations with those the California Energy Commission is considering in its proceeding under Docket 11-RPS-01, and those the California Public Utilities Commission is considering in its proceeding under Order Instituting Rulemaking, R.11-05-005. Both entities are currently receiving comments on the recently enacted California Renewable Energy Resources Act (sometimes referred to as "SB2 [(1X)]"). This is particularly important for publicly owned utilities where the CARB has the potential to impose penalties under the Public Utilities Code section 399.30(o). Rather than come up with different definitions, it would be more efficient for the regulated entities and the regulating authorities to provide consistent definitions for the same concepts. For example, under the "resource shuffling" and "electricity imports" concepts, CARB's focus of electricity is on the "delivery" of electricity while the California Renewable Energy Resources Act's focus is on procured and scheduled electricity. The California Renewable Energy Resources Act will reward utilities that comply early by allowing them to apply excess procured electricity products to satisfy subsequent compliance periods under the law. However, under the proposed concepts of "resource shuffling" and "electricity imports," LADWP may be penalized for not actually delivering electricity that it took credit for in an earlier compliance period for SB2 (1X)]. Therefore, it is unclear whether LADWP will be rewarded for early compliance with the California Renewable Energy Resources Act, yet run afoul of Cap-and-Trade regulations under AB 32. Another example is the definition of "eligible renewable energy resource" which "has the same meaning as defined in section 399.12 of the Public Utilities Code." Because the Renewable Portfolio Standard (RPS) program is currently undergoing modifications, it is unclear if this cross reference includes the entire legislative section as it does not expressly indicate that other portions of Section 399.12 are excluded. LADWP recommends that the cross reference be made to the California Energy Commission's Renewables Portfolio Standard Eligibility Guidebook, rather than Section 399.12. Without clarification on this definition, inclusion of the entire Section 399.12 would include the definition of "retail seller" which is different from "retail provider" in that it expressly does not include publicly owned utilities. Additionally, section 399.12 does not include eligible renewable energy from incremental improvements at hydroelectric facilities as allowed under existing law (Public Utilities Code, section 399.12.5). The CEC Guidebook is the standard for RPS eligibility. These definitions should be more closely aligned to avoid confusion and potential conflicts in legal interpretation, especially given the unique role that ARB will have to establish penalties for enforcement of the 33 percent RPS for publicly owned utilities. (LADWP5)

Response: We will finalize this regulation before the regulatory proceedings at the CPUC and CEC to implement SBX1 2 regulations are complete. LADWP will not be penalized if some of its electricity that is not delivered has been given credit for SB X1 2. However, any electricity that LADWP, or any other stakeholder, wishes to use in the RPS adjustment pursuant to this regulation must meet the requirements of section 95852(b) as modified.

For the reasons that we do not agree with the modifications proposed by LADWP, please see the other responses in the section that address the RPS adjustment and RECs. The regulation will limit double-counting while still allowing an emissions adjustment credit for RPS generation, provided the regulations requirements are met.

LADWP recommends that we refer for our definition of “eligible renewable energy resource” to a definition in CEC guidelines that we believe will soon be changed to be congruent with the new section 399.12 definition of the term. We believe LADWP’s recommended change would cause uncertainty and therefore, did not make the requested change.

Default Emissions Factor

I-12. Comment: LS Power requests that staff continue to evaluate the appropriateness of the default emissions factor set forth in the Mandatory Reporting Regulation, striving for consistency with the emissions determinations of other regulatory agencies and establish emissions factor that is the most reflective of imports into California. CARB should amend the default emissions factor to be more representative of generation within the WECC and consistent with the CEC’s Emissions Performance Standard. Section 95111(b)(1) of the MRR sets the default emissions factor at 0.428 Metric Tons of CO_2e/MWh. As noted in LS Power’s comments on the July 25, 2011 version of the regulation, LS Power believes that the current default emissions rate is set too low and will compromise CARB’s GHG emissions goals. An emissions factor of 0.428 creates an incentive for any out-of-state power plant with an efficiency factor higher than 0.428 to enter into a transaction with a marketer so that it can report its emissions as unspecified. Consequently, the actual GHG emissions attributable to the State will be higher than what is reported and satisfied through the cap-and-trade compliance obligation of unspecified importers. Moreover, in-state generation will be disadvantaged in the market because the emissions rate against which their compliance obligation is determined will be higher than the imputed value of unspecified emissions applied to out-of-state resources that will carry a lower compliance obligation. LS Power requests CARB continue to evaluate the default emissions factor, striving for greater consistency with the CEC's Emissions Performance Standard and a number that is more representative of generation within the WECC. Specifically, CARB should adopt a capacity-weighted average, which will result in a default emissions factor that is much closer to the EPS. LS Power also requests that CARB consider the more detailed comments on this issue that were submitted on September 27, 2011 in its response to the September 12, 2011 version of the Mandatory Reporting Regulation. (LSPOWER2)

> **Response**: This comment does not address changes identified in the second 15-day changes to the regulation. The comment addresses the MRR. No further response is required. However, we are aware of the potential for this regulation to create an incentive to shuffle resources, including an incentive for electricity importers to attempt to import power from a source with an efficiency factor (EF) greater than 0.428 metric tons of CO_2e/MWh, but claim the default EF of 0.428 pursuant to the MRR. Because such resource shuffling activity could interfere with accurate accounting, and because such activity could result in leakage, we have prohibited resource shuffling in section 95852(b)(2) of this regulation. Furthermore, the EF identified in the Emission Performance Standard (EPS) was recommended by the CEC and CPUC only as an interim default EF for consideration only until a WECC-wide tracking system was in place. WCI agreed upon a methodology to determine a default emission factor for unspecified sources that would be representative of a source on the margin. The factor is determined pursuant to the MRR. The MRR uses the WCI methodology to derive a default EF specifically for California based on power plants in WECC that are on the margin (i.e., with a capacity factor less than 60 percent.) The data will be updated annually, and the default factor will be set prior to the commencement of a compliance period. We do not agree with the use of a WECC-wide capacity-weighted average because most WECC baseload power (e.g., nuclear, hydroelectric, coal) is not available. It is already fully subscribed due to its low operating costs.

Emission Factors for Imported Power: BPA

I-13. (multiple comments)
Comment: The current regulation includes a carve out for "Asset Controlling Suppliers" which enables an entity to claim "specified" imports for all transactions regardless of the actual generation source. It is a fact that the identified Asset Controlling Supplier makes extensive market purchases with generation sources that are likely in excess of the specified level attributed to owned resources. Many of these transactions, conducted for the purpose of maximizing secondary revenues, include imports into the state of

California from carbon-emitting generation sources and should trigger a corresponding compliance obligation. Enabling an Asset Controlling Supplier to report all electricity transactions as “specified” imports with a reduced emissions profile is inequitable and inappropriate. Iberdrola Renewables strongly urges the CARB to require all electricity importers to properly identify and report the emissions associated with import transactions to ensure a level playing field and avoid a considerable and unfair market advantage for Asset Controlling Suppliers. (IBERDROLA2)

Comment: Bonneville Power Administration’s emissions are calculated dissimilarly from other imported resources. Bonneville Power Administration is defined as an Asset Controlling Supplier under the proposed Cap and Trade Regulation that is assigned a specified source emission factor by ARB for the wholesale electricity procured from its system and imported into California [section 95802(a)(14)]. As IEP understands it, BPA has a unique default emissions factor that is substantially less than the factor applied to all other unspecified imports. According to section 95111(b)(3) of the MRR, BPA has a default system emission factor that is twenty percent of the default emission factor for unspecified sources. This specific emission factor for BPA fails to recognize the interconnected nature of the Western Interconnection and treats some resources differently irrespective of their actual emissions profiles. Accordingly, ARB should adopt a single default emission factor for all unspecified purchases, and thereby effectuate similar treatment for imported power. Furthermore, in order to foster a stable, competitive environment that is not discriminatory between resources (both in and out of state), CARB should ensure that imported resources, for specified and unspecified power, accurately reflect the emissions profiles of the resources that they represent. (IEPA3)

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> **Response:** This comment pertains only to the MRR; therefore, no response is required. However, we estimated BPA’s system emission factor based on the

following considerations, in response to comments regarding ARB recognition of asset-controlling suppliers. The default emission factor for unspecified sources is set pursuant to the MRR.

BPA markets wholesale electrical power from thirty-one federal hydro projects in the Columbia River Basin, one nonfederal nuclear plant, and several other small nonfederal power plants. The dams are operated by the U.S. Army Corps of Engineers and the Bureau of Reclamation. BPA purchases a small fraction of its electricity, relative to its generation, to balance its system. BPA only sells surplus system power, after the demand of its preference customers in the Pacific Northwest has been met. In addition, surplus electricity from the BPA system has a long history of serving California load. For these reasons, ARB concluded it is more accurate and appropriate to recognize BPA as an asset-controlling supplier and assign an emission factor representative of its sources. The system emission factor for BPA is appropriate, because BPA purchases a small fraction of its electricity, relative to its generation, to balance its system, and sells only surplus system power after the demand of its preference customers in the Pacific Northwest has been met.

We do not agree there should be one default factor that would also apply to asset-controlling suppliers such as BPA.

Qualified Exports

<u>QE Adjustment Calculation</u>

I-14. Comment: SCE has serious concerns about the Qualified Exports Adjustment ("QE Adjustment") for adjusting compliance obligations based on net imports and exports. SCE strongly supports this concept, and ARB's proposed revisions to the Qualified Exports language do make the rule easier to apply. However, the current proposed QE Adjustment rules remain extremely problematic and could create perverse incentives contrary to the emissions reduction goals of AB 32. The QE Adjustment rules as currently written create significant perverse incentives for market players. Qualified Exports provisions should be designed to be easily applicable and to create incentives for proper market behavior. However, SCE has identified a number of situations where the proposed rules could penalize a market participant who chooses to import low-GHG energy instead of high-GHG energy. In other words, these provisions could provide a disincentive to import clean energy. SCE strongly urges ARB to change the structure of this rule to provide incentives to drive greenhouse gas reductions. SCE provides two proposals: (1) a simple redline change, and (2) a more robust overhaul of the QE Adjustment using a "lowest first" calculation. In either case, ARB must weigh the outcomes of these changes as well as the possibility of unanticipated outcomes. Neither proposal fully aligns market incentives correctly, although the more robust proposal could possibly fully eliminate the potential disincentives of the current rule.

The simple, redline improvement to the current proposal would set the GHG emissions rate on qualified exports as the “the lowest non-zero emissions factor” of any of the imported and exported power of that hour. This small change eliminates the disincentive to import zero-GHG energy and is likely to improve the rule. Using the ten-MWh example described above, the total compliance obligation calculated under this rule is unchanged if the importer opts to import one MWh of zero-GHG energy. Thus, this rule change eliminates the perverse incentive to avoid importing zero-GHG energy. However, this small redline solution remains imperfect, because it penalizes power marketers who import energy on the margin with cleaner or near-zero emissions factors.

Moreover, the market-changing effects of this rule on BPA-sourced or other low-emissions imports are difficult to anticipate. Before adopting this simple redline change, ARB should assess how often BPA-sourced power is expected to be the marginal import and whether the size of the BPA supply pool justifies these concerns. Accordingly, ARB should also strongly consider a more robust market design option to supersede this “no regrets” move.

As an alternative, SCE suggests a more nuanced set of QE Adjustment rules that may bring about a more robust market structure. SCE proposes a “lowest first” QE Adjustment calculation: megawatt-hours (MWh) of qualified exports should be assigned an emissions factor based on the emissions factor of that hour’s imports, in a sequence, starting with the lowest emissions rate imports first. Compare this proposal to the existing rule using the same example as above, where a power marketer imports ten MWh—nine at the system default rate and one with an emissions rate of zero—and exports five MWh. Under this new rule, one MWh of exports would be assigned an emissions rate of zero, while the remaining four would be assigned the system default emissions rate. Unlike the existing rules, or the simple redline change proposed above, this “lowest first” QE Adjustment calculation provides no disincentive for entities to import any form of cleaner energy on the margin. In addition, this approach more accurately reduces the excess GHG obligation. The QE Adjustment would thus become far more functional and effective.

SCE recommends that ARB continue to make improvements to the design and structure of the QE Adjustment. SCE’s “lowest first” approach eliminates the disincentives for importing any form of clean energy. It may not create incentives for importing cleaner energy, although other programs and policies are already in place to provide these incentives. Ultimately, the QE Adjustment should work to provide needed flexibility for power marketers while aligning market behaviors in a manner that supports the goals of AB 32 and drives market efficiency.

In light of these design deficiencies and the potential for unintended consequences, SCE continues to support market preparedness efforts, and urges ARB to revisit this topic in the upcoming market readiness rulemaking. Market preparedness efforts should include an action plan for quickly adjusting the QE Adjustment rules, as well as a full market simulation and modeling on the impacts of the cap-and-trade rule on electricity market transactions. Because prices and behavior will undoubtedly shift over time to respond to GHG pricing and regulations, proper system modeling highlight distortional or negative impacts on markets that result from the cap-and-trade regulation. Even with modeling data, some market effects may be difficult to anticipate. Thus, ARB should be prepared for market-changing consequences by articulating a strategy for revisiting and adjusting the rules as needed. (SCE4)

> **Response:** We appreciate the commenter's thoughtful analysis. SCE provides an example of an hour in which an importer imports renewable electricity with a zero emission factor; for example, wind, solar, or geothermal. If there are other imports and exports during the same hour, the importer would be allowed zero QE adjustment for the hour, while if they imported no zero emission factor power, they could use the adjustment calculated using a non-zero emission factor.
>
> We agree with SCE that it is theoretically possible that an LSE or marketer would choose not to import renewable electricity based on economic interest. If they stopped having that electricity directly delivered (if it is possible to deliver it somewhere else) we believe that in the short run, SCE's purchase of and retirement of RECs for that electricity would still be useful in reducing WECC-wide emissions, while, through the RPS adjustment, also helping SCE or its counterparty to reduce a compliance obligation.
>
> We will continue to monitor the electricity market, paying special attention to the role of the QE adjustment factor. If in our ongoing discussions with stakeholders and monitoring of the electricity market we come to believe that a new QE approach becomes necessary to maintain the program's integrity, we will recommend making either the change recommended by SCE or other modifications to the regulation, as appropriate.

I-15. Comment: Assembly Bill 32 directs CARB to account for emissions associated with all electricity consumed in the State. WPTF has previously raised concerns that the approach taken by CARB, which imputes emission liability for imports on the basis of gross electricity imports, would significantly overstate electricity consumption in the State, arbitrarily and unnecessarily raise allowance and ultimately electricity prices, and make the cap and trade regulation more vulnerable to legal challenges from electricity importers.

The modified regulation has partially addressed this concern through inclusion of a "Qualified Export (QE) Adjustment" in section 95852. Under the QE Adjustment individual entities may net exported electricity against imported electricity within same hour. However, because the QE Adjustment does not provide for netting across individual entities, it would still overestimate statewide electricity consumption due to residual exports that are not accounted.

Absent a mechanism to account for these residual exports within the cap and trade program, the market will create opportunities for electric power entities to coordinate their import and export transactions into wheel-through transactions. While this behavior would better reflect electricity consumed in the State, it would increase transaction costs for importers and place additional burden on the California Independent System Operator (CAISO). We therefore recommend that CARB work with electricity sector stakeholders, the CAISO and other California Balancing Area Authorities to develop a mechanism to ensure that electricity imports subject to the cap and trade program match net interchange.

A second problem with the QE Adjustment is the new requirement that emission rate of the qualified export be equal to the emission rate of the cleanest import or export in that hour. Consequently, whenever the export portion is of lower intensity than the import portion or when there are multiple import transactions of varying intensity, the QE Adjustment would be less than the liability that could be avoided if the transaction were conducted as a wheel-through on a single tag—which are exempt from reporting. This inconsistent treatment creates an economic incentive for increasing use of the single tag wheel-through schedule types in the CAISO, instead of the more flexible simultaneous import/export schedules, thereby increasing economic inefficiencies without reducing GHG emissions.

The requirements for the calculation of the emission intensity for the QE Adjustment are overly restrictive, unnecessary and inconsistent with the treatment of wheel-throughs. Modify section 95852(b)(5)(A) as follows:

(A) During any hour in which an electricity importer claims qualified exports and corresponding imports, the maximum amount of QE adjustment for the hour shall not exceed the product of:

> 1. The lower of either the quantity of exports or imports (MWh) for the hour; multiplied by
> 2. The <u>weighted average</u> lowest emission factor of any portion of the qualified exports or corresponding imports for the hour. <u>If the quantity of qualified exports is less than the quantity of corresponding imports for the hour, then the weighted average is calculated by ranking the imports in intensity from highest to lowest and applied to the volume from subsection (1) accordingly.</u> (WPTF3)
>
> **Response:** The commenter requests that we net across individual entities to prevent overestimating statewide electricity consumption due to residual exports that are not accounted for. We believe that economic exchanges may be simultaneous, within the hour, or non-simultaneous and typically seasonal. Simultaneous exchanges are accommodated via the provision for qualified exports adjustment to covered emissions, as a limited means to control leakage. Non-simultaneous exchanges cannot be netted, since we believe that would violate the requirements of AB 32. Pursuant to AB 32, statewide GHG emissions include both emissions from electricity generation facilities located in California and emissions from electricity that is imported and consumed. The direction given in AB 32 to account for all electricity provides equal incentives to reduce

the carbon intensity of electricity generated in California, whether it is provided for export or for consumption in-state.

WPTF states that the QE adjustment “would still overestimate statewide electricity consumption.” However, the QE adjustment does not attempt to estimate or consider statewide electricity consumption, and the compliance obligation is not solely based on emissions from electricity consumed in California. Instead, the compliance obligation falls on all GHG emissions not excluded pursuant to sections 95852.1 to 95852.2 that are due to electricity generated in California even if it is exported, and to similar emissions associated with imported electricity.

It is not clear what is meant by WPTF in regard to use of the term “residual exports.” We agree that there are some hours in which California is exporting electricity, and we did not intend for those exports to be included in any kind of QE adjustment. There is no statewide netting of exports and imports; we only allow the netting of exports and imports during an hour by the same electricity importer.

We understand that there may be hours in which one importer is importing and another importer is exporting, but we did not reduce compliance obligation for either party in such a situation. We will monitor reported data, and if we find evidence that indicates that a change to the QE adjustment is required, we will work with stakeholders under a future rulemaking.

WPTF also recommends a change to section 95852(b)(5)(A)(2), to use a weighted average emission factor. However, for reasons explained in the response to comments above, we did not make this change.

I-16. Comment: Section 95852(b)(5)(A) of the Cap-and-Trade Rule allows for an adjustment to a PSE’s emissions obligation for times when that PSE imports and exports electricity in the same hour (a “Qualified Export Adjustment” or “QE Adjustment”). Powerex supports ARB’s proposal to include a QE Adjustment in the Cap and Trade Rule. Indeed, without a QE Adjustment, the Cap-and-Trade Rule could have significant distorting effects on the California energy market. Specifically, if the Cap-and-Trade Rule does not include an appropriate method of adjusting a PSE’s emissions obligations whenever that PSE has both imports and exports during the same hour, the PSE will be incented towards a wheel through transaction in which power moves through the State rather than incurring carbon liability for electricity that was not ultimately consumed in California. A QE Adjustment potentially solves the problem by removing any incentive for the importer to select a wheel through over a set of import/export transactions for the same hour.

Unfortunately, as currently proposed, the QE Adjustment still has substantial potential to distort the underlying power markets by inflating the emission obligation of the deliverer and incenting increased use of wheel through transactions in situations where energy is being both imported and exported in the same hour. ARB proposes to calculate the adjustment by multiplying the lower of either the volume of exports or the volume of imports for the hour (MWh) by the lowest emission factor of any portion of those imports or exports. See section 95852(b)(5)(A)(1) and (2).

Powerex agrees that the volume of qualified exports should be based on the lower of the quantity of exports and imports for that hour. That is consistent with how a PSE would set up wheel through transactions to accomplish the same purpose. But it is not appropriate to require a PSE to use the lowest emission factor associated with any of the imports/exports in that hour. Restricting PSEs to using only the lowest emission factor may incent wheel throughs of unspecified power and leave lower emission imports to be imported for consumption inside the state. As currently written, PSEs will, on the margin commit to wheel through transactions, since these would be based on an intensity ranking, from highest to lowest, of the imports for that hour and applied to the volume proportionately. To eliminate any incentive for PSEs to use wheel through transactions to adjust for qualified exports, we suggest the following modifications. The suggested changes make the QE Adjustment's calculation method more akin to the calculations that underlie a typical wheel through transaction. Moreover, they also appropriately focus the calculation on the carbon intensity of the electricity being imported but not used in California. Finally, the changes eliminate the confusion that could arise under the current proposal when, as is often the case, a PSE procures export energy through the CAISO and the carbon intensity is unknown. Modify section 95852(b)(5)(A)(2) as follows:

> (2) The <u>weighted average</u> ~~lowest~~ emission factor of ~~any portion of the qualified exports or~~ corresponding imports for the hour. <u>If the quantity of qualified exports is less than the quantity of corresponding imports for the hour, then the weighted average is calculated by ranking the imports in intensity from highest to lowest and applied to the volume from subsection (1) accordingly.</u> (POWEREX2)
>
> **Response:** We appreciate Powerex's support of a QE adjustment. Powerex states that the QE adjustment will provide an incentive for wheel-throughs. While we disagree with this modification, we will monitor and analyze reported data, as discussed above. If we become convinced that the regulation has, or would have, any significant unintended consequences, we will take action to address the issue.

<u>*Transmission Loss Factor for Qualified Exports*</u>

I-17. Comment: ARB has proposed a Transmission Loss Correction Factor (TL) of 1.02 to imported electricity from unspecified and specified sources in order to account for transmission losses between the measurement at the busbar and the measurement at the first point of receipt in California. However, ARB has not included such a TL in the QE Adjustment calculation. Applying a TL factor only to imported electricity, but not applying the same TL factor credit to offsetting exported electricity, will create an inconsistency that is unfair and leads to unintended consequences. Without the TL, the

QE Adjustment will always be lower than the GHG emissions calculated for imported electricity by the 2 percent adjustment factor. Qualified Exports should be able to offset all of the GHG emissions calculated for imported electricity. Accordingly, ARB should apply the same TL factor to the QE Adjustment to maintain this consistency in the regulations. (SCE4)

> **Response:** Section 95852(b)(5) describes the requirements for the Qualified Export adjustment. Transmission losses are not applied to exports pursuant to MRR section 95111(a)(6). ARB concluded that the losses between the busbar and the last point of delivery inside California will remain under the cap and will not be subtracted from the compliance obligation.

Potential Overstatement of Imports

I-18. Comment: Citi has identified and done yeoman's work investigating and defining the issue of "net imports" across scheduling coordinators. Current drafts of calculation rules provide for netting imports and exports within an individual scheduling coordinator's portfolio, which is appropriate. However, the lack of a way to calculate net imports and exports across different Scheduling Coordinators does indeed appear to create a significant systemic bias towards aggregate overstatement of the level of imported power. Such an overstatement will add extra costs to imports, thus unintentionally and inappropriately disadvantaging them commercially against indigenous resources with which they would otherwise be economically competitive. Furthermore, by definition, such a cost overstatement will redound to consumers, artificially and inappropriately increasing the cost of the GHG reduction program for consumers.

MSCG observes that identifying the problem is much simpler than identifying the solution. We do not at this point have a specific recommendation for resolving the issue. However, we do support the view that the issue is valid, significant, and merits further investigation and ultimately, resolution. We would observe that the largest practical problem in identifying the solution will be in developing a way to allocate a "credit" of some sort, due to the aggregate overstatement of imports, back to individual market participants who are responsible for submitting compliance instruments. Two variant ideas that suggest themselves are 1) some form of "backward looking" credit, or refund, of compliance instruments, or 2) a forward looking "reduction factor" to the compliance obligation, based on historical calculations, regularly adjusted and trued up. There may very well be other types of solutions. This problem probably can't be resolved in time for the October Board vote. Therefore, we urge the ARB to "flag" this issue for further development, and resolution in 2012 before the start of the compliance obligation in 2013. (MSCG4)

> **Response:** We thank MSCG4 for the comment. Statewide GHG emissions include emissions from delivered electricity from both electricity generation facilities located in California and emissions from electricity that is delivered and consumed. AB 32 requires that we account for all electricity to provide equal

incentive to reduce the carbon intensity of electricity generated in California, whether it is provided for export or for consumption in-state. Pursuant to Health and Safety Code (HSC) section 38505(m), "Statewide greenhouse gas emissions" means the total annual emissions of greenhouse gases in the state, including all emissions of greenhouse gases from the generation of electricity delivered to and consumed in California, accounting for transmission and distribution line losses, whether the electricity is generated in state or imported. Economic exchanges may be simultaneous, within the hour, or non-simultaneous and typically seasonal. Simultaneous exchanges are accommodated via the provision for qualified exports adjustment to covered emissions as a limited means to control leakage. Non-simultaneous exchanges cannot be netted, since that would violate the requirements of AB 32. We believe that the regulation as it stands is sufficient and that electricity importers may find ways, such as scheduling more wheel-throughs, that would reduce any possible overstatement of the level of imported power. Since no commenter has shown convincingly that a change is needed in the QE adjustment, and since we are unaware of any quantitative analysis on possible “overstatement of the level of imported power,” we did not change the adjustment. We will monitor reported data and will make modifications in the future if we find evidence that the QE adjustment would lead to unintended negative consequences.

e-Tags and Commerce Clause

I-19. (multiple comments)
Comment: PacifiCorp remains concerned that the regulation continues to rely on the use of e-Tags to determine when an entity is a first-deliverer under the definition Electricity Importer. The changes made do not resolve the fundamental problem with relying on e-Tags to establish the first-delivered electricity and in fact exacerbate the risk of potential legal challenges to the regulations. To minimize these risks and provide greater clarity, PacifiCorp encourages ARB to identify the first deliverer provisions as an issue that will be further evaluated before the first cap-and-trade auction in July 2012.

The importer provisions should not exclusively rely on NERC e-tags, and ARB should not remove reference to title and potential regulation of downstream purchasers in these provisions. The Proposed Regulation includes substantial revisions to the definitions for Electricity Importer (95802(a)(87)) and Imported Electricity (95802(a)(137)). The definitions no longer refer to the title holder when determining the entity that will be considered the importer subject to ARB jurisdiction, and thus the first deliverer with the cap-and-trade compliance obligation. Instead, the regulations rely exclusively on the purchasing-selling entity (PSE) identified on the North American Electric Reliability Corporation (NERC) e-Tag.

The regulations also remove language that would have provided: “When PSEs are not subject to the regulatory authority of ARB, including tribal nations, the electricity importer is the immediate downstream purchaser or recipient that is subject to the regulatory authority of ARB.” Further, language was added to the definition of Electricity

Importer stating that “for facilities physically located outside the state of California with the first point of interconnection to a California balancing authority’s transmission and distribution system, the importer is the facility operator or scheduling coordinator.” These changes are problematic for three reasons: 1) they potentially violate the dormant commerce clause and will therefore expose the cap-and-trade regulation to litigation risk; 2) they do not solve the complex problem of how to identify the correct entity importing power into California that is consumed in California; 3) they lack clarity and will therefore create confusion and uncertainty for parties transacting at trading hubs outside California.

The importer definitions potentially constitute an over-reach of California’s jurisdiction. The aforementioned sentence beginning “when PSEs are not subject to the regulatory authority of ARB. . .” served as an explicit recognition that ARB does not have jurisdiction over interstate transactions occurring wholly outside the state. The previous version of the Proposed Regulation properly recognized that ARB can only regulate the entity that holds title when power crosses the state line, typically the downstream purchaser when title is passed to a purchaser at a delivery point physically located out of state. This legal structure has ARB jurisdiction properly attached when the power is within the state boundary. The removal of this language is exacerbated by the simultaneous deletion of reference to title in the beginning of the definition.

ARB relies on the PSE designation on the e-Tag, and specifically the PSE identified in the last segment of the physical path of the e-Tag to identify the electricity importer. As PacifiCorp noted in its comments on the July 25th version of the Proposed Regulation, e-Tags are not used to establish title to energy or transmission. Rather, e-Tags were originally designed as a tracking system for interchange transactions. As such, e-Tags facilitate communication and tracking of interchange transaction information between counterparties, balancing authorities, and transmission providers. Using e-Tags as the exclusive determinant for identifying electricity importers is inappropriate because, as is more fully described below, there are instances when the entity identified as the PSE in the last segment of the physical path crossing into California does not hold title to the power and is therefore not importing energy to be consumed in California. Further, because e-Tags are not intended to establish or confirm title, there are not currently mechanisms in place to monitor, track, and ensure that the PSE on the e-Tag is correctly identified in every instance. Adopting rules that impose compliance obligations based on e-Tag information will require PSEs to develop controls to ensure accuracy of commercial information on e-Tags, which are tools designed to ensure reliability and not to document commercial activity.

Attaching a California compliance obligation to an entity who is not importing energy into California could amount to California’s regulation of activities outside of the state of California. The removal of the language in the definition that refers to the entity that holds title does not solve these fundamental flaws associated with the definition and the use e-Tags to identify importers.

PacifiCorp, in its capacity as a FERC-jurisdictional service provider, has wholesale transactions for its system power where it is identified as the PSE on the physical path for energy scheduled into California even though the purchasing entity took title to the power at a point within PacifiCorp's multi-state balancing authority area. As an example, PacifiCorp routinely sells energy to the CAISO in the real-time market at the California-Oregon border (COB), a trading hub made up of multiple scheduling points, including Captain Jack and Malin500. In this example, there are two relevant e-Tag line segments: 1) JohnDay-MALIN500; and 2) MALIN500-NP15. PacifiCorp contends that the sale to the CAISO occurs at Malin. PacifiCorp has title to the energy from the source to Malin, where the CAISO takes title to the energy and delivers it into California, sinking the energy in NP15. However, in compliance with CAISO Operating Procedure – 2510, the e-Tag lists only PacifiCorp as a PSE. Most importantly, the e-Tag lists PacifiCorp as the PSE on the MALIN500-NP15 segment, where the energy enters California. In this example, then, PacifiCorp could be determined to be the electricity importer and be required to carry the cap and trade compliance obligation. PacifiCorp asserts that it is the CAISO, and not PacifiCorp, that is importing electricity into California to be consumed in California. It is not appropriate for the ARB to attach a compliance obligation on an out of state entity that is not importing electricity into California.

If these provisions are implemented as is, the Cap-and-Trade Program will be vulnerable to legal challenge. The Commerce Clause of the United States Constitution (Article I, Section 8, Clause 3) empowers Congress to regulate interstate commerce. This provision has been interpreted by courts to prohibit states from regulating activities which occur wholly outside the State.

In the context of electricity imports, when title is conferred from the seller to the purchaser at a location outside of California, the commercial transaction takes place wholly outside of California. ARB may have authority to regulate the purchaser that is delivering energy to be consumed in California, but ARB will not have jurisdiction over the seller. However, if the selling entity is nevertheless identified on the e-tag as the PSE on the physical path coming into California, and ARB seeks to regulate the selling entity as the importer, then ARB will exceed the extent of its jurisdiction in violation of the Commerce Clause. These risks should be avoided because they will create uncertainty and price volatility in the cap-and-trade markets.

PacifiCorp is sympathetic to ARB's desire to have a simple mechanism that will clearly identify the entity importing electricity into California to be consumed in California. However, due to complexity of the wholesale market and transmission scheduling systems, it is highly unlikely that there is any way to simply and clearly establish the entity that actually holds title to energy as it crosses into California and then is consumed in California. Certainly, for the reasons described above, the desired data is not practically captured via an e-Tag. Further, reliance on the e-Tag mechanism to identify the importer is also problematic because it calls into question the constitutionality of the Cap-and-Trade Program as it implies to importers.

PacifiCorp proposes that a more practical and legally supported solution would be to calculate, on some regular interval, the quantity of unspecified net imports and require the buyer/importer (located in California) to allocate the related compliance obligation to sellers. This would more accurately and easily account for imported energy, as well as wheels and exports, and does not rely on scheduling information that may be subject to change and does not necessarily reflect actual energy flow. In this way, imports could be calculated based on actual flow data that already is or could be captured by the CAISO. The buyer/importer would be identified as the entity with the compliance obligation and it would then determine how to spread the costs of compliance to sellers. Further, this solution could allow for more certainty in the wholesale market and could more accurately capture the allowance price embedded in the price of energy because the price will be based on a net consumption amount.

In sum, the risk of litigation and lack of clarity created by the importer definitions is an issue that needs resolution by ARB. Regardless of whether or not ARB is willing to consider the solution described above, more work is needed in order to work through the complexities associated with identifying the electricity importer. Since staff has indicated that there will not be another 15 day rulemaking package released before the October Board hearing, PacifiCorp requests that ARB identify the importer definitions and first deliverer provisions generally as a topic area subject to further rulemaking activity in 2012. These issues should be resolved well before the July 2012 start of the cap-and-trade auctions. PacifiCorp continues to encourage ARB staff to consult a range of technical experts on issues affecting the wholesale energy market and continues to offer its own technical expertise from the perspective of a balancing authority and a MJRP. (PACIFICOR4)

Comment: The CPUC/CEC interim decision on the point of regulation for the electricity sector recommended the first deliver as the "owner" of the electricity. Point of regulation for the electricity sector was extensively vetted during the CPUC and CEC joint proceeding (Rulemaking 06-04-009) in which the "First Deliverer" was recommended in March 2008 by the CPUC and CEC jointly. More specifically, the agencies further recommended to the ARB that the first deliverer be the entity that holds title to the power. This has been a long-standing position held by the majority of the electric sector since 2008. As the rulemaking evolved since that time, it appears that ARB has focused on the use of NERC E-tags to identify the purchasing-selling-entity holding title to the power at the point of delivery to California, and only recently as part of this Second 15-Day Modified Text removed the ownership requirement.

LADWP strongly recommends that ARB retain the current emissions reporting requirements for entity reports under MRR that are based on electricity that is owned or under a power purchase agreement. Since Intermountain is directly linked to LADWP's Balancing Authority area, the entity that holds title to the power at the busbar is known. Such approach more correctly aligns the emissions reporting, compliance obligation, and attestation requirement to the party that has the most discretion and control over the electricity.

In the most recent amendments (September 12, 2011), the definition of "first deliverer" stripped the requirement that the electricity importer hold title to the power being imported. Only at the time of this most recent amendment (September 12, 2011) did the definition of "first deliverer" strip the requirement that the electricity importer hold title to the power being imported. The public notice for this Second 15-Day Modified Text provides a vague description but no real explanation for why these definitional changes were made. LADWP strongly recommends that ARB hold off on making these definitional changes until further consideration can be given to the amendments as part of the new proceeding in 2012. The ARB Board should not adopt the amendments to definitions that strip the requirement to "hold title" as these changes will have a ripple effect on specified imports that is not well understood and may be unintentional, and should be avoided. LADWP strongly recommends that the ARB not strike this requirement (i.e. to hold title) as part of the adoption of this regulation without adequate vetting from all stakeholders. This change has the potential to impact any entity that is importing electricity from a specified source, and it is essential that ARB seek different viewpoints from those that advocated only recently to remove this requirement from the definition. LADWP's ultimate objective is to ensure that the proper entity is attributed the emissions obligation (for fossil emissions) or zero emissions attribute (nuclear, hydroelectric or renewables) and that the regulation does not inadvertently impose an emissions obligation on zero-emitting specified imports, regardless of how the owner of the imported electricity elected to have it imported. (LADWP5)

Comment: NERC defines the Purchasing-Selling Entity" as "the entity that purchases or sells, and takes title to, energy, capacity, and Interconnected Operations Services..." and yet the ARB has elected to remove a fundamental part of this definition—title and responsibility—and ignore the market segments on the NERC E-tag where a PSE may also be listed. According to the NERC Electronic Tagging Function Specification, Version 1.8.1, "market segments contain information that describes the market information, such as the identity of the market participant, the firmness of energy the market participant is delivering, and the physical segments the entity is responsible for providing." LADWP strongly recommends that these definitional changes being proposed by staff in sections 95802(a)(264), 95852(b)(1)(C), and 95852(b)(3), be revisited in order to provide consistency and alignment between the Cap-and-Trade program and standard wholesale market transactions. (LADWP5)

> **Response:** We disagree with PacifiCorp. The regulation does not exclusively rely on the PSE on an e-Tag as the identifier of the first deliverer. Some imported electricity does not cross balancing authority areas (BAA) boundaries, and the MRR relies on other data to establish the identity of the first deliverer in these cases.
>
> PacifiCorp claims that our use of the term “PSE” is something other than the meaning of PSE used in federally approved documents and definitions that set reliability standards nationwide. Some of the documents are proprietary, but can be viewed by scheduling coordinators and PSEs. LADWP5, we believe correctly, quotes NERC’s definition of PSE. PacifiCorp asserts that use of e-Tags in the

regulation will be problematic for three reasons: it potentially violates the dormant commerce clause, it does not identify the correct entity importing power into California that is consumed in California, and it lacks clarity and will therefore create confusion in the electricity market.

While we agree that ARB does not have jurisdiction over commercial transactions occurring wholly outside of the state, we do believe that ARB has jurisdiction where electricity is delivered into California state boundaries. The regulation applies the compliance obligation to first deliverers who are electricity importers for electricity imported into California, which are identified as PSEs on e-Tags. We apply the compliance obligation on entities that deliver power into a California point where it is sold, or used in some other way by an importer that acquires the electricity outside of California. There are no regulatory requirements until such time as electricity has entered California. This confines obligations under the regulation to electricity that is brought into the state, and the system allows California to most effectively account for such electricity without imposing requirements that could possibly violate the Commerce Clause.

Commenter raises a concern that an entity bringing electricity into the state may not own title to such electricity, and regulation of that entity bringing electricity into California is improper unless that entity also owns title to such electricity. As described above, we rely on e-Tag data as a demonstration that electricity was delivered from a point outside of California to a point inside of California and for identification of the entity associated with such electricity. Commenter is mistaken in its belief that we use e-Tag information as a proxy for title. The definitions of electricity importer, electricity exporter, purchasing-selling entity, and marketer were modified to clarify that delivery and not title is the critical determinant of responsibility. ARB must rely on a clearly identifiable and verifiable entity that delivers electricity into California. Which party holds title to electricity may become a matter of dispute between counterparties and does not provide the certainty needed in a mandatory GHG program. The regulation in this context simply looks at electricity that is brought into California and the entity that has done so without determining who holds title. Accordingly, commenter’s discussion asserting that CAISO takes title to electricity at nodes outside of the state is not the key determination. It is the entity that brings electricity from a point outside of California to a point inside of California who we consider as an electricity importer in the regulation, and for which we use e-Tag information. We believe that this provides a simple and straightforward means to identify the electricity importer for electricity brought into California.

Commenter additionally expresses angst that the definition of electricity importer lacks clarity and will cause confusion in the electricity market. We disagree and believe the title requirement would have only added to uncertainty for regulated entities, because determinations on which entity holds title for each transaction could be subject to dispute and may be documented in less accessible and reliable forms than e-Tags. ARB concluded that the existing NERC e-tag system used to support reliability standards for the North American bulk power system provides consistent and reliable source data and independent documentation of electricity delivered across balancing authority areas. NERC is the electric reliability organization (ERO) certified by the Federal Energy Regulatory Commission to establish and enforce reliability standards for the bulk-power system. The current regulation language is intended to provide the certainty which commenters have requested by specifying a straightforward mechanism such as e-Tag data that ARB will use to determine whether an entity is a first deliverer.

In sum, we do not agree that PacifiCorp, or any electricity importer, as implied in the comment, is not able to correctly identify the PSE on the last segment of an e-Tag that schedules delivery of electricity to a FPOD in California. A sale cannot be made unless either: (1) the electricity is delivered to a California FPOD by the importer that identifies itself as the PSE, or (2) the non-importer PSE on the previous segment finds a counterparty willing to purchase the electricity at the last Point of Receipt (POR) outside of California and to agree to be the PSE. PacifiCorp also comments on our removal of language that would have identified a downstream purchaser as the electricity importer. As we have discussed above, the PSE and SC listed on the e-Tag is the importer of electricity when the e-Tag indicates that electricity has been moved from a point outside of California to a point inside of California. Because we believe e-Tags will provide an accurate and reliable means of tracking electricity that is delivered into California, as well as the entity associated with such deliveries, we see no need at this time to designate additional entities as possible electricity importers.

With respect to the comment of LADWP, we take a first-deliverer approach, as recommended by the CPUC and CEC. The regulation clearly identifies the first deliverer, and we note that the understanding of the first deliverer approach has evolved significantly during ARB's work with stakeholders over the last six months in coordination with CEC and CPUC staff. We developed the concept in greater detail for use in this regulation, and we very much appreciate the hard work of CEC and CPUC and stakeholders in the process that identified the first-deliverer approach. The fourth paragraph of the LADWP5 comment above addresses the MRR, so we do not respond here.

LADWP is also concerned with the removal of the words "entity that holds title to delivered electricity is" in the definition of electricity importer for the case when the electricity is delivered between balancing authority areas. We share LADWP's desire to ensure compliance obligations are properly assigned. As discussed more fully above, we believe the regulation will do so by identifying the PSE associated with electricity delivered from a point outside of the state to a point inside of the state. Additional determinations regarding title for each transaction could create uncertainty in the market, because determinations on which entity holds title for each transaction could be subject to dispute among the parties and may be documented in less accessible and reliable forms than e-Tags.

Finally, we will continue to work with stakeholders to ensure there is clarity as we work to implement this system.

I-20. (multiple comments)
Comment: ARB staff made changes to a number of definitions that appear to resolve a problem with unspecified electricity imports into the CAISO pool (unspecified electricity is electricity that cannot be tracked back to the source). However, those revisions may result in unintended consequences for reporting emissions and compliance obligations for other electricity imports that are specified (originate from a known facility or source—can be renewable, coal, nuclear, etc). Changes to the following Cap and Trade and MRR definitions remove the requirement that the importer "hold title" to the power, including: 1) electricity importers, 2) marketer, and 3) purchasing selling entity. In the electricity sector, there are contractual arrangements where an entity that owns the electricity may not have the transmission capacity to schedule it into California and thus contracts with another entity to "move" it into California.

At this point, ARB has not adequately vetted this issue before making the amendments they made in this Second 15-Day set of amendments, and it appears that this "tiny" change will have a ripple effect on imports that otherwise are very straightforward and uncomplicated. CCEEB recommends that ARB not remove the requirement to hold title to power imports until the potential impacts on reporting and compliance obligations for specified imports is more fully vetted and it can be demonstrated that such changes to key definitions are both warranted and do not cause harm to other entities with specified imports. ARB recommends that the ARB Board direct staff to further evaluate this potential change to electricity imports as part of the new regulatory proceeding in 2012. (CCEEB4)

Comment: LS Power is engaged in the development, acquisition and management of power generation and transmission infrastructure. In addition to its natural gas-fired facilities, LS Power is currently investing in wind and solar resources. LS Power, as an importer of power into the CA markets, seeks, as do other market participants, regulatory certainty around the newly developing cap-and-trade market and to have the regulations promulgated by this agency withstand the legal challenges that are sure to arise on a myriad of issues. LS Power's primary concern with the most recent regulatory package is that CARB continues to rely on e-tags to designate ownership of imported power and has removed language which utilized the title holder of power as the power crosses the political border of California as the point of regulation over imported power. Title is the concept that makes the assertion of CARB's jurisdiction over imports much clearer from a legal and commercial perspective. In the current version, the cap-and-trade program does not adequately contemplate the interstate nature of the western electricity system or the legal bounds of CARB's jurisdiction. For the reasons explained below, the cap-and-trade program, with respect to its treatment of electric transactions occurring at locations outside of California, violates the Commerce Clause of the U.S. Constitution which limits the ability of a state to regulate commercial activities occurring outside its borders.

To provide a means of correcting this deficiency, LS Power requests that CARB, in its resolution approving the cap-and-trade program, include a direction to staff which identifies the electricity importer definition as a specific topic that will be addressed in a subsequent rulemaking before the cap-and-trade program takes effect.

The September 12, 2011 Revisions to the Cap-and-trade Regulation Expose the Program to Litigation Risk by Violating the Commerce Clause of the United States Constitution. The stated intent of the cap-and-trade program, as it applies to the electricity sector, is to impose a compliance obligation on in-state power plants and imports into this state from out-of-state power plants. At the highest level, these points of regulation appear simple. But in its application to the interstate electric marketplace, the regulation seeks to impose CARB's jurisdiction over activities that are exceedingly complex. The wholesale electricity markets are operated in real time, across state and international borders. In California, there are several balancing authority areas, some of which extend beyond the State's borders. In other words, the western electricity system is a quintessential example of "interstate commerce", and as CARB seeks to regulate the California portion of this system, CARB must carefully evaluate the legal scope of its jurisdictional reach. The most recent changes to the regulation obscure the line between regulating in-state activities and those which occur entirely out-of-state. If these issues are not remedied, LS Power is concerned that the regulation is susceptible to legal challenge on the basis of the Commerce Clause.

The September 12, 2011 version of the regulation includes three substantial revisions to the definition for Electricity Importer (Proposed 17 Cal. Code Reg. section 95802(a)(87)). First, the following sentence has been deleted: "when PSEs are not subject to the regulatory authority of ARB, including tribal nations, the electricity importer is the immediate downstream purchaser or recipient that is subject to the regulatory authority of ARB." This sentence helped clarify that when CARB does not have jurisdiction over an import because the delivery occurred out-of-state, CARB's jurisdiction will apply to the entity that it can regulate: the purchaser bringing the power into the state. Second, the electricity importer definition no longer refers to the entity holding title to the power, and instead relies solely on the purchasing-selling entity (PSE) identified on the NERC e-tag. As noted in LS Power's August 11th Comment letter on the previous version of the regulation, e-tags do not accurately track ownership of power, and are an imprecise and inappropriate tool for determining the reach of CARB's jurisdiction.

Third, the electricity importer definition includes new language stating that the operator of an out-of-state facility is an importer when the first point of interconnection is to a "California Balancing Authority." As noted above, a California Balancing Authority can have territorial areas located outside of California and an operator of such an out-of-state facility may not hold title to power when it comes across the border into California. Collectively, these changes will lead to circumstances where CARB's jurisdictional reach seeks to regulate a seller of electricity even though the seller never owns power as the power is transmitted across California's borders.

States cannot regulate commercial activities occurring wholly outside their borders, and doing so constitutes a violation of the Commerce Clause. Article 1, Section 8, Clause 3 of the United States Constitution provides that "The Congress shall have power to regulate Commerce with foreign nations, and among the several States, and with the Indian Tribes." The importance of the Commerce Clause extends beyond simply describing the power of Congress. The Commerce Clause has been interpreted by courts to implicitly govern the power of states. For example, in New York Life Insurance Co. v. Head, 234 U.S. 149 (1914), the U.S. Supreme Court determined that "it would be impossible to permit the statutes of Missouri to operate beyond the jurisdiction of that State . . . without throwing down the constitutional barriers by which all the States are restricted within the orbits of their lawful authority and upon the preservation of which the Government under the Constitution depends."

More recently, in Edgar v. Mite Corp., the U.S. Supreme Court interpreted the Commerce Clause to "preclude the application of a state statute to commerce that takes place wholly outside of the State's borders, whether or not the commerce has effects within the State." (See, Edgar v. Mite Corp. 457 U.S. 624, 642, (1982), emphasis added.) This language was quoted by the Court in Healy v. the Beer Institute, 491 U.S. 324 (1989), when the Court struck down a Connecticut statute requiring out-of-state shippers to affirm that the prices charged to wholesalers in Connecticut were no greater than prices charged in neighboring states. In Healy, the Court concluded that the Connecticut statute had the "undeniable effect of controlling commercial activity occurring wholly outside the boundary of the State." (Healy v. The Beer Institute, at p. 337). Importantly, in both of these cases, the underlying activities that started the lawsuits had impacts on the states. Even though the commerce had effects within the state, the commerce occurred wholly outside the state's borders. Similarly, in the context of an electricity import, when title to the power is transferred to a purchaser at a point physically located out-of-state, the commercial activity occurs wholly outside the State of California. Even though the power eventually comes into California, CARB's jurisdiction cannot extend to the sellers in these instances without offending the Commerce Clause. Moreover, CARB's California program, and the manner it would attach to importers and operators of certain generators located outside the state, will undoubtedly influence the prices for interstate transactions occurring at market hubs located outside California.

Thus, in the current form, the cap-and-trade regulation creates a significant risk that the program could be challenged because it violates the Commerce Clause. Such litigation risk creates uncertainty for the program and undermines confidence in the cap-and-trade markets, which is especially needed in the incipient stages of the program. Moreover, out-of-state sellers participating in CAISO markets by delivering to out-of-state nodes, such as LS Power, who may choose not to challenge the regulations, will be at a competitive disadvantage compared to out-of-state sellers that may not choose to submit to CARB's jurisdiction. In sum, the invalid extension of CARB's jurisdiction through the importer definitions is a significant deficiency in the cap-and-trade program that needs to be remedied before the program starts. Accordingly, LS Power requests that CARB specifically acknowledge these deficiencies through a Board Resolution if and when the cap-and-trade program is adopted and approved at the October Board hearing. The board resolution should specifically direct staff to address these concerns in a subsequent rulemaking before the start of the program (i.e. early 2012). (LSPOWER2)

> **Response:** The regulation relies, via the MRR, on a variety of documentation to verify electricity transactions reports, including NERC e-Tags, settlements data, and contracts. ARB concluded that the existing NERC e-Tag system used to support reliability standards for the North American bulk power system provides consistent and reliable source data and independent documentation of electricity delivered across balancing authority areas. NERC is the electric reliability organization (ERO) certified by the Federal Energy Regulatory Commission to establish and enforce reliability standards for the bulk-power system. NERC develops and enforces reliability standards; assesses adequacy annually via a 10-year forecast and summer and winter forecasts; monitors the bulk power system; and educates, trains, and certifies industry personnel.
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> When electricity is delivered across balancing authority areas (BAAs), NERC e Tags are created to request, approve, and document the interchange transaction from source (generation) to sink (load), designating the market path and physical path from first point of receipt (POR) to final point of delivery (POD). Therefore, for electricity that crosses BAAs, imports, exports, and wheels are defined pursuant to subsection 95102(a) with respect to the location of the first POR the final POD as documented on NERC e-Tags. This convention, based on NERC Reliability Standards and supporting business practices, provides for rigorous and consistent accounting of emissions from electricity.
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> Purchasing-selling entities are designated on NERC e-Tags for each segment of the physical transmission path, which provides the means for reporting entities to clearly identify the quantities of electricity they import, export, and wheel across the California border. Use of NERC e-Tags to document is necessary for consistent reporting and verification. Determining which transactions are specified or unspecified relies on written power contracts (and supporting records), settlement data, and invoices.
>
> We modified the definitions of “electricity importer,” “electricity exporter,” “purchasing-selling entity,” and “marketer” to clarify that delivery and not title is the critical determinant of responsibility. ARB must rely on a clearly identifiable and verifiable entity that delivers electricity into California. Which party holds title to electricity may become a matter of dispute between counterparties and does not provide the certainty needed in a mandatory GHG reporting program.

The cap-and-trade regulation applies the compliance obligation to first deliverers who are electricity importers for electricity imported into California. In most cases, these importers are identified as PSEs on e-Tags, as discussed above. We apply the compliance obligation on entities that deliver power into a California point where it is sold, or used in some other way by an importer that acquires the electricity outside of California. ARB does not apply a compliance obligation on transactions outside of California, and ARB does not attempt to regulate commercial activities outside its borders, as discussed in our previous response.

While we agree that interstate commerce takes place within the western electricity system, transactions take place within identifiable jurisdictions at the State level. We note that we have read the legal arguments put forward by parties involved in the CPUC and CEC process in which those agencies recommended the first-deliverer approach. We regulate electricity through the entity that delivers power into the California grid. We apply the compliance obligation to the entity that brings the power across the state border and either: (1) owns and keeps the power in the next stage of delivery, or (2) sells the power to another entity at the FPOD in California. Thus, while the WECC is clearly a multi-jurisdictional system, ARB regulates transactions in California.

LS Power (and PacifiCorp) comment that ARB explicitly recognized that we do not have jurisdiction over certain cases, but misinterpret what we meant by deleting language that included the words “tribal nations.” ARB may not have jurisdiction over actions of tribal nations, and that was the reason we considered including the language that was removed. However, we decided that we need not address the activities of tribal nations that are PSEs in section 95802(a)(87). We are only aware of one power plant in California operated by a tribal nation, and e-Tags are not required to be used to schedule that power because it is generated and may be consumed within the boundaries of the State of California.

LS Power misstates the regulation in claiming that the electricity importer definition newly state that “the operator of an out-of-state facility is an importer when the first point of interconnection is to a California BA.” The regulation states that in such cases the electricity importer is “the facility operator or scheduling coordinator. If the out-of-state facility is connected directly to a California BA, the facility can both sell and schedule the electricity into California, in which case they are the importer. Alternatively, the facility desiring to sell electricity for import to California can find an SC that is willing to be the first deliverer and pay the compliance obligation. We believe that parties will work this out in the electricity market. As noted above, an entity cannot schedule through the CAISO system without selling the power in a California transaction at a California FPOD.

FERC Jurisdiction

I-21. Comment: ARB should consider Federal Energy Regulatory Commission (FERC) exclusive jurisdictional issues when it comes to the regulation of imported wholesale energy. The definitions of electricity importer and imported electricity, as well as many other elements of the proposed regulations that may affect the wholesale energy market (inside and outside California), may be problematic in light of the Federal Energy Regulatory Commission's (FERC) exclusive jurisdiction to regulate the rates, terms, and conditions of sales for resale of electric energy in interstate commerce by public utilities. To the extent that the cap-and-trade program regulates the wholesale energy market by setting prices or establishing conditions for participation in the market, it may be subject to federal preemption. PacifiCorp strongly encourages ARB to engage FERC staff to ensure that no aspects of the cap-and-trade program are pre-empted by federal law and do not violate the Federal Power Act.
(PACIFICOR4)

> **Response:** The Supremacy Clause of the United States Constitution declares unlawful state laws that "interfere with, or are contrary to," federal law. *Hillsborough County, Fla. v. Automated Med. Labs., Inc.*, 471 U.S. 707, 712 (1985) (quoting *Gibbons v. Ogden*, 22 U.S. (9 Wheat.) 1, 211 (1824)); see also U.S. Const. art. VI, cl. 2. Preemption analysis starts "with the assumption that the historic police powers of the States were not to be superseded by the Federal Act unless that was the clear and manifest purpose of Congress." *Rice v. Santa Fe Elevator Corp.,* 331 U.S. 218, 230 (1947). "[T]he purpose of Congress is the ultimate touchstone of preemption analysis." *Cipollone v. Liggett Group,* 505 U.S. 504, 516 (1992) (internal quotation marks omitted). Federal law can preempt state law in three ways. First, Congress may expressly preempt state law. Second, preemption may be inferred where Congress has occupied a given field with comprehensive regulation. Third, a state law is preempted to the extent that it actually conflicts with federal law. An "actual conflict" exists when "'compliance with both federal and state regulations is a physical impossibility[.]'" Automated Med. Labs., Inc., 471 U.S. at 713.
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> A preemption claim involving state actions that conflict with the Federal Power Act ("FPA") are predicated on the Supremacy Clause. See *Duke Energy Trading & Mktg., L.L.C. v. Davis,* 267 F.3d 1042, 1055 (9th Cir. 2001). The FPA grants to FERC "'exclusive authority to regulate the transmission and sale at wholesale of electric energy in interstate commerce.'" *Transmission Agency of N. Cal. v. Sierra Pac. Power Co.,* 295 F.3d 918, 928 (9th Cir. 2002) ("TANC") (quoting *New England Power Co. v. New Hampshire,* 455 U.S. 331, 340 (1982)). Through the FPA, "'Congress meant to draw a bright line easily ascertained, between state and federal jurisdiction …. This was done in the Power Act by making [FERC] jurisdiction plenary and extending it to all wholesale sales in interstate commerce except those which Congress has made explicitly subject to regulation by the States.'" *Nantahala Power & Light Co. v. Thornburg,* 476 U.S. 953, 966 (1986)

(quoting *Fed. Power Comm'n v. S. Cal. Edison Co.,* 376 U.S. 205, 215-16 (1964)).

When enacting the Federal Power Act, Congress gave no indication that it intended to preempt state environmental programs such as greenhouse gas regulations. The regulation here is designed and intended to regulate greenhouse gas emissions in California and is not intended to regulate the rates, terms, or conditions of sales of electric energy in interstate commerce. Therefore, regulation was not expressly preempted.

“Field preemption occurs when the federal statutory scheme is sufficiently comprehensive to infer that Congress left no room for supplementary regulation by the states.” *Gadda v. Ashcroft,* 363 F.3d 861, 869 (9th Cir. 2004). “When the federal government completely occupies a given field or an identifiable portion of it . . ., the test of preemption is whether ‘the matter on which the State asserts the right to act is in any way regulated by the Federal Act.’” *Pac. Gas & Elec. Co. v. State Energy Res. Conservation & Dev. Comm’n,* 461 U.S. 190, 212-13 (1983) (quoting *Rice v. Santa Fe Elevator Corp.,* 331 U.S. 218, 236 (1947)).

One purpose of the federal statutory scheme concerns the reasonableness of interstate power rates and nondiscriminatory access to interstate power transmission. In contrast, California’s purpose for enacting AB 32 was to reduce emissions of greenhouse gases, and we are proposing to regulate the environmental impacts of electric generation and consumption. The FPA’s regulation of wholesale sales does not cover the environmental impacts associated with electricity generation and consumption. The commenter asserts that certain definitions in the regulation may impact the wholesale electricity market, but has not specified how such definitions could result in regulation by ARB of the wholesale electricity market. That some part of the regulation could indirectly affect the electricity market does not demonstrate that the provision will result in regulation of wholesale electricity sales, such as setting prices or establishing conditions for participation in the wholesale electricity market. Therefore, this regulation is a separate field related to the regulation of greenhouse gas emissions unrelated to the rates or access to power transmission.

If it is impossible to comply with both state law and federal law, then the state law is preempted. See *Gade v. Nat’l Solid Waste Management Ass’n,* 505 U.S. 88, 108 (1992). The commenter has not indicated that it would be impossible to comply with the regulation and federal law. Because the regulation here relates to greenhouse gas emissions and does not purport to regulate wholesale electric energy sales, we do not believe that a conflict exists.

Moreover, the FPA leaves room for state environmental regulation. Indeed, 16 U.S.C. section 824(a) states: "Federal regulation . . . [under the FPA extends] only to those matters which are not subject to regulation by the States." This

> broad savings clause supports the conclusion that because air pollution is subject to regulation by the States, and not by the FPA or FERC, state regulation of GHG emissions caused by the generation and consumption of electricity is not preempted by the FPA, but may be regulated by the States. While such GHG regulation may have some impact on the wholesale prices paid for electricity, it is no more preempted by the FPA than state regulations limiting the amount of other pollutants that may be emitted by electric power plants—that may affect the cost of generating electricity and therefore indirectly affect the price of wholesale electricity. For these reasons, we do not believe the FPA preempts this regulation.

CAISO on E-Tags

I-22. Comment: The California Independent System Operator Corporation (ISO) appreciates the opportunity to provide comments in response to the above-referenced notice issued by the California Air Resources Board (ARB) on September 12, 2011. As part of this notice, the ARB modified the definition of Electricity Importers in its proposed regulation. The ISO recommends that the ARB change this definition to clarify that the ISO is not an electricity importer when scheduling energy and/or capacity during an emergency in the ISO balancing authority area or in an adjacent balancing authority area. ARB's proposed regulation defines Electricity Importers to mean "marketers and retail providers that deliver imported electricity." The definition also provides in part:

> For electricity delivered between balancing authority areas, the electricity importer is identified on the NERC E-tag as the purchasing-selling entity (PSE) on the last segment of the tag's physical path with the point of receipt located outside the state of California and the point of delivery located inside the state of California.

The ISO is a nonprofit public benefit corporation chartered under the laws of the state of California for the purpose of operating and maintaining the reliability of the statewide electric transmission grid for the benefit of the citizens of California. The Federal Power Act requires that the ISO plan and operate the power grid in compliance with federal and regional mandatory reliability standards.

By way of example, the disturbance control performance standard BAL-002-0 requires the ISO as a balancing authority to deploy and utilize its operating reserves to stabilize the power grid and return interconnection frequency to defined limits within 15 minutes after the occurrence of a contingency. As part of complying with reliability standards, the ISO must have operating agreements with adjacent balancing authorities that shall, at a minimum, contain provisions for emergency assistance. The ISO must also request emergency assistance if it cannot comply with specific standards such as disturbance control performance standard BAL-002-0.

As ARB is aware, the ISO operates a wholesale electricity market. The ISO does not provide electricity to retail end users. The ISO does not own any electric generating resources inside or outside the state of California and does not operate a portfolio of contracts for the delivery of power from entities importing electricity into California. Despite these facts, the ISO may be required to request emergency assistance from other balancing authority areas, including balancing authority areas outside of the state of California. In addition, the ISO may be required to provide emergency assistance to an adjacent balancing authority area.

Emergency assistance may involve a schedule of energy and/or capacity between balancing authority areas. This schedule may result in the identification of the ISO as a purchasing selling entity on an E-tag. This convention may arise because during periods of emergency assistance there is not another scheduling coordinator to identify on the E-tag. The ISO tariff provides specific criteria to avoid the need for requesting emergency assistance from other balancing authority areas.

As a result, the need for the ISO to request emergency assistance is extremely rare. For example, in 2010, the ISO relied on emergency assistance once, which amounted to less than one ten-thousandth of a percent of all power delivered on the ISO grid that year.

The ISO recommends that the ARB add the following language to the definition of Electricity Importer to exempt the ISO from the definition when the ISO schedules energy and/or capacity during an emergency in the ISO balancing authority area or in an adjacent balancing authority area:

> The CAISO is not an "electricity importer" if it is identified as a purchasing-selling entity on the NERC E-tag as a result of requesting or providing emergency assistance during a declared emergency in order to comply with applicable reliability criteria, pursuant to either an agreement required by NERC standards regarding emergency assistance or section 42.1.5 of the CAISO tariff or a successor provision.

This exemption is appropriate for at least two reasons. First, ARB should not make the ISO a point of regulation for the extremely rare occurrence and minimal quantities of power it may request from or provide to neighboring balancing authority areas during an emergency. Second, when the ISO requires or must provide emergency assistance, it acts under tight time constraints with one purpose only—ensure the reliability of the electricity grid. Under these circumstances, the ISO should not pause to consider the type and location of a resource providing energy and/or capacity from a neighboring balancing authority or whether the ISO should or should not appear as a purchasing-selling entity on an E-tag. ARB's regulation governing mandatory reporting of greenhouse gas emissions does not apply to generating units designated as emergency generators in a permit issued by an air pollution control district or air quality management district. A similar exemption is appropriate here. (CAISO)

> **Response:** We did not make the modification requested by CAISO; however, CAISO is not a PSE or an electricity importer. ARB treats all first deliverers of

electricity impartially, does not distinguish between electricity delivered under normal operations versus emergency operations, and does not determine whether a PSE was entered in error on a NERC e-Tag. However, as noted by the CAISO, the definition of electricity importer specifies that for "electricity delivered between balancing authority areas, the electricity importer is identified on the NERC e-Tag as the purchasing-selling entity (PSE) on the last segment of the tag's physical path with the point of receipt located outside the state of California and the point of delivery located inside the state of California." Since CAISO is only registered as an Operating/Security Entity in the Electric Industry Registry maintained by NERC, and CAISO is not registered as a PSE, CAISO does not meet the definition of an electricity importer.

Resource Shuffling Support

I-23. (multiple comments)
Comment: SCE supports the modifications to the resource shuffling provisions. In section 95802(a)(251), ARB revised the definition of "Resource Shuffling," removing two hypothetical situations where delivery of electricity to the California grid could be considered resource shuffling. In addition, ARB has removed the unnecessary use of the term "fraud" in section 95852(b)(2). SCE agrees with the changes, and thanks ARB staff for responding to SCE's concerns. The scenarios were too broadly written and could too easily encompass situations where a covered entity was either (1) acting for valid economic dispatch reasons, or (2) engaging in activities that resembled resource shuffling with no intent to circumvent emissions regulations. (SCE4)

Comment: Pacificorp supports the changes to the resource shuffling provisions and plans to further revise and clarify their applicability. PacifiCorp supports staff's indication that there will be an opportunity to provide further input on those sections. PacifiCorp is pleased to see that the September 12th update to the Proposed Regulation addresses PacifiCorp and other parties' concerns about the Resource Shuffling provisions by removing reference to fraud and the confusing standards for "historically serving load in California" (see section 95802(a)(251)). (PACIFICOR4)

Comment: LS Power supports the changes to the resource shuffling provisions, provided that there will be further clarification before the program starts. LS Power expresses its support for the changes to the Resource Shuffling provisions and staff's recognition that further clarification is needed for those provisions. The Resource Shuffling provisions (Propose 17 Cal. Code Reg. section 95802(a)(251), and 95852(b)(2)) have been modified to remove two specific activities from Resource Shuffling. LS Power supports the general goal of discouraging importers from misrepresenting their GHG emissions. However, parties, including LS Power, expressed significant concerns in comments on the July 25, 2011 version of the Resource Shuffling provisions because it was unclear when an otherwise legitimate and commercially rational transaction could become illegitimate because it fell within the vague definition. The most recent changes on this topic are an improvement. (LSPOWER2)

Comment: Iberdrola Renewables applauds the CARB's action to remove the reference to "fraud" from the definition of "Resource Shuffling" in the revised version of the cap and trade regulation. (IBERDROLA2)

> **Response:** We appreciate commenters' support of the modifications, and recognition of the need to address resource shuffling.

I-24. Comment: The definition of resource shuffling should be clarified. The Proposed Changes remove troublesome sections that were included in the definition that was circulated in the First 15-Day Change Notice, but the text of the abbreviated definition is very vague. The definition should be revised to include sufficient detail to enable an entity to know in advance whether a particular energy transaction constitutes resource shuffling. This is particularly important, given that section 95852(b)(2) requires attestations that no resource shuffling has occurred. Additionally, while the concept of resource shuffling should apply only to electricity generated outside California, the definition does not contain this limitation. The general phrase "delivery of electricity to the California grid" could include electricity from in-state generating facilities. It is not appropriate to extend the concept of resource shuffling to in-state generation given that the emissions liability for in-state generation is imposed directly on the operator of the generating facility and cannot be "shuffled" in any way. The impact of the resource shuffling provisions on the wholesale electricity market should be fully evaluated. Given the harsh penalties that the ARB would impose for resource shuffling and the uncertainty about what actually constitutes resource shuffling, the resource shuffling provisions that are currently in the Proposed Changes could remove liquidity from the wholesale electricity market, reducing the potential for cost-effective trades as well as for trades that enhance system reliability while increasing electricity prices. That would be a negative and counterproductive consequence of having an overly broad and ambiguous resource shuffling rule.

The potential for the resource shuffling provisions to discourage emission reductions should be fully evaluated. Although subparagraph (B) of the definition of resource shuffling that was circulated in the First 15-Day Change Notice has been deleted in the Proposed Changes, it remains unclear under the revised definition whether an entity that permanently retires a power plant that has an emissions factor that is higher than the default emissions factor and replaces the output of the plant with unspecified system power would be considered to be engaging in resource shuffling. This would be an undesirable result as the consequence of retiring the high-emitting plant would be to reduce GHG emissions in total. The resource shuffling provisions should not require covered entities to continue operating high-emitting plants until the deadline imposed by the SB 1368 Emissions Performance Standard (EPS). Entities should be able to withdraw from such plants before the EPS deadline without fear of committing resource shuffling. A full review of resource shuffling should be undertaken in 2012. SCPPA understands that the Board intends to provide an opportunity for full review of the resource shuffling provisions in a new rulemaking in 2012. SCPPA strongly supports having that new rulemaking. The Resolution should provide for that new rulemaking. Suggested wording for such a provision is set out below:

> BE IT FURTHER RESOLVED THAT the Board directs the Executive Officer to initiate a public process for the review of the resource shuffling provisions in section 95802(a) and section 95852(b) no later than February 2012, for the purpose of ensuring the appropriate operation of those provisions, including clarifying that those provisions apply only to electricity generated outside California and in a jurisdiction where a GHG emissions trading system has not been approved for linkage by the Board.

SCPPA looks forward to providing further input on resource shuffling during the review process in 2012. (SCPPA8)

Comment: The Resource Shuffling provision does not provide clarity regarding financial divestiture of an emission source [section 95802(a)(251), page A-44; and section 95852(b)(2), page A-90] The definition of resource shuffling, as amended in the Second 15-Day Modified Text has been shortened to the following in section 95802 (page A-44): "Resource Shuffling means any plan, scheme, or artifice to receive credit based on emissions reductions that have not occurred, involving the delivery of electricity to the California grid." LADWP remains concerned that the resource shuffling provision, even as revised in the Second 15-Day Modified Text, does not provide clarity that early divestiture of LADWP's share of Navajo Generating Station would be treated as an emission reduction, and not as resource shuffling. It is LADWP's interpretation that such divestiture should be recognized as an emission reduction, especially since the very same action (i.e. financial divestiture) in 2019 would be recognized by the state of California as contributing to emission reductions toward the 2020 statewide goal. If this provision remains in the regulation, then LADWP strongly recommends that the ARB Board include a directive in its Board resolution that staff address LADWP's concerns regarding financial divestiture as soon as possible in the new regulatory proceeding so as to not impede our near-term negotiations to divest this asset prior to 2019 or long-term resource planning to replace this asset with cleaner generation resources. (LADWP5)

Comment: The resource shuffling provision and related attestation requirement are included in section 95851(b)(2) (page A-90) as they relate to the emission categories used to calculate compliance obligations for first deliverers of electricity. Separately, the Second 15-Day Modified Text includes new amendments to the definition of "Electricity Importers" (pg A-18) that removes the requirement that the importer hold title to imported electricity. First, LADWP is not a "scheduling coordinator" (a unique term used by CAISO), but it is a "scheduling agent" for Glendale Water and Power (GWP) and Burbank Water and Power (BWP) for electricity imported from Intermountain Power Project (Intermountain). Based on these new amendments, it appears that LADWP may be identified as the first deliverer, not just for its own electricity imports, but also electricity owned by GWP and BWP that LADWP schedules and imports into California on their behalf.

Second, LADWP is a retail provider for the load that it serves, but it is not a retail provider for load served by GWP or BWP. Currently, the MRR entity-level emissions report aligns correctly with each retail provider's respective electricity imports from Intermountain. However, if this amendment is adopted, then LADWP becomes the first deliverer for GWP and BWP electricity imports from Intermountain. LADWP will not only be required to report on its LADWP entity-specific emissions for electricity it owns, but it will also have to add in the emissions for electricity from Intermountain that is owned and used by GWP and BWP for their retail load. Conversely, BWP and GWP entity-level emission reports will not include emissions associated with their share of Intermountain electricity imports, which might lead to more confusion and less transparency for the public. The result is that the entity-level report will no longer accurately reflect the true emissions profile for electricity imported for each affected retail provider. For BWP's and GWP's share, LADWP will be subject to regulatory requirements such as surrendering allowances and enforcement action. This outcome provides an inaccurate reflection of LADWP's emissions, and should be avoided.

Third, the entity that is best positioned to make decisions regarding whether or not to import power into California from a specified source like Intermountain is the entity that holds title to the power. LADWP, as a scheduling agent, does not make the decision for BWP or GWP. Instead, BWP or GWP would identify in their schedule how much energy they intend to have imported into California. As such, when it comes to electricity imports that originate from a known, specified source like Intermountain, it is the owner of the power that has the most control and discretion over what is done with it, whether to lay it off outside California or import it into California, and not the entity scheduling the power.

LADWP is also concerned that it will be required to sign a resource shuffling attestation, as noted above, for these same non-LADWP emissions. As an illustration, if the electricity is "cargo" and the first deliverer is the "mail courier" this approach equates to making the mail courier responsible as if it is the owner of the contents of the cargo (i.e. the emissions profile of the electricity). In fact, the mail courier may not own the cargo and may be contracted to deliver the cargo, but does not make any decisions regarding the contents. The mail courier cannot buy or sell the cargo either, and can only deliver it from point A to point B as determined by the owner of the cargo. The only accurate information that the mail courier can reasonably attest to is how much cargo he delivered on his truck (MWhs), when it was delivered (date/time), and to what location inside California (point of interconnection). The mail courier cannot reasonably attest to the contents or destination of cargo that may be on another truck (i.e. resources that are shuffled elsewhere). (LADWP5)

Comment: When ARB revises the Resource Shuffling sections, ARB should recognize that a multi-jurisdictional utility's resource decisions made pursuant to a multi-state cost allocation methodology does not constitute resource shuffling. Currently, the definition provides that “Resource Shuffling” means any plan, scheme, or artifice to receive credit based on emissions reductions that have not occurred, involving the delivery of electricity to the California grid." The regulation also still requires regulated entities to attest to not engaging in Resource Shuffling (section 95852(b)(2)). As a MJRP, PacifiCorp allocates its resources to loads in different states consistent with regulatory directives.

In their current form, the Resource Shuffling provisions still lack clarity with respect to the treatment of a MJRP's resources and should not be adopted in their current form, unless the staff explicitly notes in the regulation or elsewhere that the Resource Shuffling provisions will be subject to further revision and clarification in 2012. When ARB revises the Resource Shuffling provisions, ARB should recognize that a multi-jurisdictional utility's resource decisions are made pursuant to a specific cost allocation methodology, and potentially other legitimate regulatory or commercial activities such as the provision of ancillary services, and will not constitute resource shuffling. PacifiCorp appreciates the opportunity to provide comments on the September 12th 15-day modifications of the Proposed Regulation. Overall, we would like to remind the Board that a multi-jurisdictional utility has unique reporting and compliance challenges, and that the Proposed Regulation should be subject to further stakeholder vetting to ensure that the Cap-and-Trade Program is properly considers interstate activities such as the sale and operation of the western-wide wholesale electricity markets. The final regulation as implemented in July 2012, when the first auction occurs, should strive to better recognize the extent of ARB's jurisdiction over out-of-state activities. Also, PacifiCorp reiterates its proposal to apply the Cap-and-Trade compliance obligation based on a calculated net import amount to identify the electricity importer and PacifiCorp looks forward to working with staff towards the successful adoption and implementation of the Cap-and-Trade Program. (PACIFICOR4)

Comment: The remaining language stating that "'Resource Shuffling' means any plan, scheme, or artifice to receive credit based on emissions reductions that have not occurred, involving the delivery of electricity to the California grid" still lacks clarity. LS Power therefore requests that the Board specifically address this as an area that will be subject to further revision before the start of the cap-and-trade program. In addition, staff should continue to consider LS Power's previous suggestion to include additional changes to the regulations that would allow for an upfront determination that a specified importer is not engaged in resource shuffling where CARB has issued a specified emissions factor for a particular facility that is applied to output sold into the CAISO or other California markets. (LSPOWER2)

Comment: Significant uncertainty remains with regard to what specific activities will constitute Resource Shuffling under the final regulation. Iberdrola Renewables requests the CARB to identify this issue for further rulemaking and commit to work with interested stakeholders to clarify conditions under which import transactions would be considered Resource Shuffling. (IBERDROLA2)

Comment: ARB revised the definition of "Resource Shuffling" in section 95802(a)(251), removing two hypothetical situations where delivery of electricity to the California grid could be considered resource shuffling. In addition, ARB has removed the unnecessary use of the term "fraud" in section 95852(b)(2). CCEEB appreciates the changes. The scenarios were too broadly written and could too easily encompass situations where a covered entity was either (1) acting for valid economic dispatch reasons, or (2) engaging in activities that resembled resource shuffling with no intent to circumvent emissions regulations. However, the regulation still lacks the necessary clarity to regulated entities regarding what electricity transactions would constitute resource shuffling and which transactions should be excluded. For example, the regulation does not include procedures that can be followed during emergency scenarios when a utility may be called upon to provide power for another load-serving entity. Because the resource shuffling provision has the potential to impact the wholesale electricity markets beyond California, CCEEB recommends that ARB address additional resource shuffling provisions as soon as possible as part of the new regulatory proceeding in 2012 and seek the input from other entities, including the Federal Energy Regulatory Commission (FERC), North American Electric Reliability Corporation (NERC), and Western Electricity Coordinating Council (WECC). (CCEEB4)

Response: SCPPA8 comments that the definition of resource shuffling should be "revised to include sufficient detail to enable an entity to know in advance whether a particular energy transaction constitutes resource shuffling." LS Power requests a provision be added to allow for an up-front determination regarding resource shuffling. We did not make the requested changes, because resource shuffling could take a multitude of varied forms. Our intent is to address all forms of the prohibited conduct, and we believe that unintentional conduct has been excluded from this definition by use of the terms "plan, scheme or artifice" in the definition.

We agree, in general, that it is unlikely that resource shuffling could occur involving in-state generating facilities. However, if an in-state generator failed to comply with the requirements of the MRR and sold power with high GHG emissions in an export, and then imported zero-emission power, that could be resource shuffling. In such a case, an entity could be in violation of the MRR and also could be part of a resource shuffling plan. Our prohibition against resource shuffling is applicable to all delivered electricity.

This regulation imposes a compliance obligation based on GHG emissions; we expect to see some changes in the electricity market. We expect that, all else being equal, first deliverers will prefer electricity from sources with lower emissions, within the context of seeking cost-effective electricity supply. We will monitor reported data pursuant to the MRR, and if there is evidence that indicates that resource shuffling is occurring, we will consider a new rulemaking to mitigate such consequences by working with stakeholders to make needed changes, and we will continue to consider electricity market operations.

ARB applauds any action by an entity to permanently retire a power plant with a high emissions factor. It is not our intent to capture typical or normal market activity, or implementation of plans by a utility to meet EPS requirements. Where the commenter has engaged in conduct to receive credit for emissions reductions that have occurred, such conduct would not be resource shuffling. In Resolution 11-32, the Board directed the Executive Officer to continue discussions with stakeholders to identify and propose, as necessary, during the initial implementation of the cap-and-trade program, potential amendments to the regulation, including the definition of “resource shuffling,” to: (a) provide appropriate incentives for accelerated divestiture of high-emitting resources by recognizing that these divestitures can further the goals of AB 32; and (b) ensure that changes in reported emissions from imported electricity that serves California do not result merely in a shift of emissions within the Western Electricity Coordinating Council region, but instead reduce overall emissions.

We agree with LADWP that it will be identified as the first deliverer for deliveries that it makes for GWP and BWP, and we do not contest LADWP’s assertion that it is not the retail provider that serves GWP and BWP customers. However, we note that the compliance obligation is applied to the first deliverer of electricity and not the retail provider. In LADWP’s words, this is electricity that “LADWP schedules and imports into California on their behalf.” LADWP is the electricity importer, which is the first deliverer with the compliance obligation. We do not define “scheduling coordinator” in the regulation. However, as a “scheduling agent” for GWP and BWP, we recommend that LADWP make arrangements with GWP and BWP so that those entities reimburse LADWP for the compliance obligation that LADWP incurs on electricity delivered for GWP and BWP.

ARB will continue to clarify the resource shuffling definition and prohibition in 2012. If we believe that a new rulemaking in 2012 is necessary to prevent unintended consequences, we will initiate a new rulemaking. SCPPA’s comments on a non-existent resolution do not apply to the second 15-day changes to the regulation, and require no response. However, we look forward to SCPPA's continued participation in discussions of resource shuffling, and we will work with the Board to develop the resolution as the Board sees fit, taking into consideration requests of SCPPA and other commenters.

PacifiCorp’s comment emphasizes the particularities of an MJRP. We do not agree that the resource shuffling provisions are unclear. The legitimate activities that PacifiCorp engages in pursuant to state law and multi-jurisdictional agreements are not resource shuffling. With respect to the proposal reiterated by PacifiCorp, we modified the regulation to change how we calculate the QE adjustment. This is our method of calculating the compliance obligation to recognize net imports for each hour in which an electricity deliverer is both exporting and importing power.

LS Power asks for additional changes to “allow for an upfront determination” regarding resource shuffling. We did not make the change. We note that we will continue to engage with LS Power and other stakeholders on this topic. If, after further consideration, we are convinced that additional changes are needed, we will initiate a new rulemaking.

I-25. (multiple comments)
Comment: The Revisions regarding resource shuffling set forth in sections 95802(a)(245) and 95852(b)(1) clearly move in the right direction. These changes acknowledge the concerns raised by NCPA and other stakeholders that legitimate market operations and transactions can be inappropriately caught up in the wide net that was cast by the definition proposed in the first proposed 15-day revisions. NPCA understands that CARB intends to continue to review this matter and attempt to define the prohibited transaction as part of a new Rulemaking that will address revisions to the Rulemaking. In doing so, NCPA urges staff to work closely with the electricity sector stakeholders. It is imperative to the success of the Cap-and-Trade Program and the efficient and cost-effective operation of the electricity grid throughout the Western Electricity Coordinating Council that this definition be carefully crafted. The final definition adopted by CARB has the potential to adversely impact electric utilities and should be carefully crafted to ensure that the result is not a prohibition on standard and existing electric transactions that maximize the efficient use of the State's electric transmission system and economic dispatch of electric generation resources. Rather, resource shuffling should be narrowly defined in order to avoid adverse and inadvertent impacts on typical electricity market activity, but broad enough to ensure that true malfeasance is prohibited. NCPA looks forward to continuing to work with CARB Staff on this crucial issue. NCPA also supports CARB's removal of the reference to fraud, and the Proposed Revisions to the attestation requirements that properly acknowledge that the affirmation is done by the individual in his or her official capacity as an employee of the compliance entity, rather than personally. (NCPA4)

Comment: More clarity is needed on resource-shuffling and requirements for specification of imports. In comments on the first 15 day package, WPTF and other stakeholders raised serious concerns that provisions in that package related to "resource-shuffling" could result in electricity importers being subject to financial penalties and potentially criminal consequences for events that are outside that entity's control. In response to these concerns, CARB staff has modified the definition of resource-shuffling to eliminate specific elements that were considered particularly problematic. We appreciate CARB's efforts to address stakeholder concerns, but unfortunately, the revised language is now so broadly defined that it provides no clarity or regulatory certainty regarding which transactions would be considered legitimate specified or non-specified imports and which would be considered resource-shuffling.

To remedy these shortcomings, WPTF strongly urges CARB to further develop the provisions related to resource-shuffling and specification of imported electricity through a formal stakeholder process next year. The goal of this process should be to develop a clearer definition of resource shuffling and requirements for specified imports that are consistent with goals of AB32 and normal electricity market practices. WPTF also recommends the development of guidance documents that could be used by importers and verifiers to determine whether imports can or must be claimed as specified. Such guidance documents should provide examples of normal and anticipated import scenarios. (WPTF3)

Comment: Sections 95802(a)(251) and 95852(b)(2) have been modified to remove the specific activities constituting Resource Shuffling, as well as the reference to fraud. The remaining portion of the definition states that resource shuffling is a "plan, scheme, or artifice to receive credit based on emissions reductions that have not occurred, involving the delivery of electricity to the California grid." While the current revisions are an improvement, the application of the Resource Shuffling provisions in their current form will still cause significant confusion among regulated entities. Without clarification, regulated entities will not know when otherwise legitimate market transactions would be perceived as avoiding an emissions obligation, and thus constitute resource shuffling. In light of the fact that the current language is unclear and still creates a level of uncertainty, IEP requests that CARB identify these provisions as an area that will be subject to further rulemaking activity before the start of the program. (IEPA3)

> **Response:** We developed the definition of "resource shuffling" to have a precise legal meaning. We believe that once understood completely, the current definition will not have unintended consequences. However, as discussed above, we will continue to work with stakeholders to consider their concerns, and to take actions, if necessary, to clarify our treatment of resource shuffling.
>
> For reasons discussed elsewhere, we do not agree with WPTF that the prohibition of resource shuffling could result in penalties to electricity importers for "events that are outside that entity's control."
>
> IEPA3 seeks additional clarification of resource shuffling, and requests that we identify these provisions as "an area that will be subject to further rulemaking activity before the start of the program." We acknowledge their request to continue to work with stakeholders, to further their understanding that our intent is not to capture typical electricity transactions, but to capture transactions that are attempting to report emissions from electricity imports that are not representative of transactions occurring in the WECC.
>
> In Resolution 11-32, the Board directed the Executive Officer to continue discussions with stakeholders to identify and propose, as necessary, during the initial implementation of the cap-and-trade program, potential amendments to the regulation, including the definition of "resource shuffling," to: (a) provide appropriate incentives for accelerated divestiture of high-emitting resources by recognizing that these divestitures can further the goals of AB 32; and (b) ensure that changes in reported emissions from imported electricity that serves California do not result merely in a shift of emissions within the Western Electricity Coordinating Council region, but instead reduce overall emissions.

Resource Shuffling Clarification

I-26. Comment: The resource shuffling provisions require additional clarification; further work is needed to refine the cap-and-trade rule's definition of "resource shuffling." Powerex appreciates that ARB has revised the definition of "resource shuffling" in response to the concerns raised by Powerex and other stakeholders in the comments on ARB's first set of proposed 15-Day Modifications to the two rules that provisions in the definition could have subjected electricity importers to civil and even criminal penalties for circumstances entirely outside of their control. However, the newly proposed definition is sufficiently vague that the regulated community does not have certainty as to what ARB would consider legitimate specified or non-specified imports of electricity and what would be considered illegal "resource shuffling." Accordingly, Powerex urges ARB to clarify the scope of the resource shuffling provisions of the Cap-and-Trade Rule in a formal stakeholder process next year. Powerex also requests that next year ARB develop guidance documents (with example scenarios) that importers and verifiers can use to determine whether imports can or must be claimed as specified under the Cap-and-Trade Rule. In anticipation of the additional work on the provision, Powerex recommends that ARB modify the definition of "resource shuffling." Modify section 95802(a)(251) as follows:

> (251) "Resource Shuffling" means any plan, scheme, or artifice to receive credit based on emissions reductions that have not occurred, involving the delivery of electricity to the California grid, in accordance with any additional guidance developed by the California Air Resources Board. (POWEREX2)

Comment: The relationship between section 95111(g)(4) of the MRR and the cap-and-trade rule's definition of resource shuffling remains unclear. In its August 11, 2011 comments, Powerex asked ARB to explain the relationship between resource shuffling, as that term is defined in the Cap-and-Trade Rule, and the "specified source" requirements of section 95111(g)(4) of the MRR. Section 95111(g)(4) appears to list characteristics whereby if at least one of them is applicable to an electricity delivery from a specified source, that delivery will not be considered to be resource shuffling. ARB did not respond to Powerex's request for clarification. If, indeed, the characteristics listed in section 95111(g)(4) of the MRR are intended to function as categories of "safe harbor" under the resource shuffling provisions, then Powerex urges ARB to make the following changes. First, in order to satisfy the United States' obligations under NAFTA, the special treatment afforded to the federally-owned power suppliers under Section 95111(g)(4)(B) must be extended to provincially-owned entities such as Powerex, which is wholly owned and controlled by BC Hydro, a foreign sovereign. As noted above in Section I above, NAFTA's National Treatment standard requires that Powerex and BPA be accorded parity treatment. Modify section 95111(g)(4)(B) as follows:

> (B) Deliveries from existing federally or provincially owned hydroelectricity facilities by exclusive marketers. Electricity from specified federally or

provincially owned hydroelectricity facility delivered by exclusive marketers. (POWEREX2)

Comment: Powerex urges ARB to eliminate section 95111(g)(4)(C) of the MRR because the phrase "deliveries from existing federally owned hydroelectricity facilities allowed under contract" appears to excuse from the definition of resource shuffling the precise type of activity that the Cap-and-Trade Rule seeks to discourage. The clause seems to presume that deliveries by the exclusive marketers of federally owned hydroelectricity facilities are limited to surplus electricity and, thus, would never constitute resource shuffling. But this is a false assumption. In fact, there is no way to ensure that entities with such contracts would limit their deliveries of this electricity to California to its surplus rather than maximizing the delivery of this federal power to California and back filling its load requirements with market power. Rather, as currently drafted, this provision would give these entities an incentive to engage in such activity to maximize the value of the emissions-free power from the federal facilities. Surely such activity would qualify as a "scheme or artifice to receive credit based on emission reductions that have not occurred"—*i.e.*, resource shuffling. Accordingly, Section 95111(g)(4)(C) should be deleted. (POWEREX2)

Response: Powerex states that the new definition of resource shuffling is too vague for the regulated community to have certainty about what would be considered resource shuffling. We did not accept Powerex's proposed modification of section 95802(a)(251). We believe that the definition, which uses words with specific legal meaning, is sufficient to enable first deliverers to discern what is considered to be resource shuffling and what is not.

We note that portions of Powerex's comment not responded to immediately above are pertinent to the MRR. No additional response is required here because the comment is outside of the scope of the second 15-day changes to the regulation. Because Powerex also submitted comments in the MRR rulemaking, these parts will be addressed in that venue.

Reserve Section for Resource Shuffling

I-27. Comment: The changes to the resource shuffling provisions in the second 15-day Modifications are a step in the right direction, but the definition of resource shuffling remains vague—too vague to be useful and too vague for the required resource shuffling attestations. ARB should use a placeholder for the definition until it undertakes further study of the issue.

SDG&E and SoCalGas share ARB's concern for the integrity of the cap-and-trade program and the desire to prohibit resource shuffling. The changes to the resource shuffling provisions in the second 15-day Modifications move in a positive direction, but the definition is too vague for market participants to know whether they have engaged in such action. For ARB to effectively deal with Resource Shuffling, the definition of resource shuffling needs to be more precise. ARB has indicated that it will refine the definition of resource shuffling next year and that should be part of the Board Resolution adopting the regulation.

Given the proposed attestation about resource shuffling, however, the definition should be reserved until it is fully fleshed out. No entity could sign an attestation based on the current vague definition of resource shuffling, where ARB is the sole determinant of what the definition means. The Cap-and-Trade Regulation should leave a placeholder for the precise definition of Resource Shuffling or should eliminate the attestation. Modify section 95802(a)(251) as follows:

> (251) “Resource Shuffling” ~~means any plan, scheme, or artifice to receive credit based on emissions reductions that have not occurred, involving the delivery of electricity to the California grid.~~ (SEMPRA4)
>
> **Response:** Sempra also contends that the definition of resource shuffling remains “too vague to be useful and too vague…for the required attestations.” We disagree, for reasons stated in response to Comments I-25 through I-27. We did not make the proposed modification. We have defined resource shuffling precisely, with specific words that require a plan, scheme or artifice on the part of a party for its action to fall under the definition. In Resolution 11-32, the Board directed the Executive Officer to continue discussions with stakeholders to identify and propose, as necessary, during the initial implementation of the cap-and-trade program, potential amendments to the regulation, including the definition of “resource shuffling,” to: (a) provide appropriate incentives for accelerated divestiture of high-emitting resources by recognizing that these divestitures can further the goals of AB 32; and (b) ensure that changes in reported emissions from imported electricity that serves California do not result merely in a shift of emissions within the Western Electricity Coordinating Council region, but instead reduce overall emissions.

Scheduling Coordinators

I-28. (Multiple comments)
Comment: The resource shuffling provision is included in section 95851(b)(2) [sic] (page A-90) as they relate to the emission categories used to calculate compliance obligations for first deliverers of electricity. Separately, the Second 15-Day Modified Text includes new amendments to the definition of "Electricity Importers" (pg A-18) that removes the requirement that the importer hold title to imported electricity. First, LADWP is not a "scheduling coordinator" and Burbank Water and Power (BWP) for electricity imported from Intermountain Power Project (Intermountain). Based on these new amendments, it appears that LADWP may be identified as the first deliverer, not just for its own electricity imports, but also electricity owned by GWP and BWP that LADWP schedules and imports into California on their behalf. Second, LADWP is a retail provider for the load that it serves, but it is not a retail provider for load served by GWP or BWP. Currently, the MRR entity-level emissions report aligns correctly with each retail provider's respective electricity imports from Intermountain. However, if this

amendment is adopted, then LADWP becomes the first deliverer for GWP and BWP electricity imports from Intermountain.

LADWP will not only be required to report on its LADWP entity-specific emissions for electricity it owns, but it will also have to add in the emissions for electricity from Intermountain that is owned and used by GWP and BWP for their retail load. Conversely, BWP and GWP entity-level emission reports will not include emissions associated with their share of Intermountain electricity imports, which might lead to more confusion and less transparency for the public. The result is that the entity-level report will no longer accurately reflect the true emissions profile for electricity imported for each affected retail provider. For BWP's and GWP's share, LADWP will be subject to regulatory requirements such as surrendering allowances and enforcement action. This outcome provides an inaccurate reflection of LADWP's emissions, and should be avoided. Third, the entity that is best positioned to make decisions regarding whether or not to import power into California from a specified source like Intermountain is the entity that holds title to the power. LADWP, as a scheduling agent, does not make the decision for BWP or GWP. Instead, BWP or GWP would identify in their schedule how much energy they intend to have imported into California. As such, when it comes to electricity imports that originate from a known, specified source like Intermountain, it is the owner of the power that has the most control and discretion over what is done with it, whether to lay it off outside California or import it into California, and not the entity scheduling the power.

The resource shuffling attestation (section 95851(b)(2)) is problematic for a first deliverer that does not hold title to imported electricity. LADWP is concerned that it will be required to sign a resource shuffling attestation for non-LADWP emissions. As an illustration, if the electricity is "cargo" and the first deliverer is the "mail courier" this approach equates to making the mail courier responsible as if it is the owner of the contents of the cargo (i.e. the emissions profile of the electricity). In fact, the mail courier may not own the cargo and may be contracted to deliver the cargo, but does not make any decisions regarding the contents. The mail courier cannot buy or sell the cargo either, and can only deliver it from point A to point B as determined by the owner of the cargo. The only accurate information that the mail courier can reasonably attest to is how much cargo he delivered on his truck (MWhs), when it was delivered (date/time), and to what location inside California (point of interconnection). The mail courier cannot reasonably attest to the contents or destination of cargo that may be on another truck (i.e. resources that are shuffled elsewhere).

LADWP strongly recommends that ARB retain the current emissions reporting requirements for entity reports under MRR that are based on electricity that is owned or under a power purchase agreement. Such an approach more correctly aligns the emissions reporting, compliance obligation, and attestation requirement to the party that has the most discretion and control over the electricity. (LADWP5)

Comment: LADWP is concerned that for some specified sources of imported electricity, the amendments that are being proposed in sections 95802(a)(264), 95852(b)(1)(C), and 95852(b)(3), may result in these imports being incorrectly assigned default emissions under circumstances where the first deliverer that is scheduling the power into California on behalf of another party assumes responsibility as the first deliverer, and therefore must also include such imports as part of their MRR report. However, the entity scheduling the power under this scenario cannot demonstrate ownership in the facility or a written power contract for that electricity. This could have the potential unintended consequence of assigning default emissions to non-emitting specified imports that are currently reported based on ownership or contract rights. For example, a transmission outage occurs and the owner of electricity from a nuclear or hydroelectric generating facility must make arrangements to have that power imported through another transmission path by another entity that has transmission rights, but does not hold title to the power. Under this scenario, the regulation would assign default emissions to that zero-emission electricity for no other reason than the entity scheduling the power does not own the power. This outcome is unreasonable and does not accommodate commonly occurring situations related to specified imports. To add more complexity to this, the entity that schedules this zero-emitting power into California that is now assigned default emissions must also surrender allowances on behalf of the party that holds title to the power. This outcome is unreasonable and should be avoided. A separate issue of transparency also arises when the first deliverer of renewable energy is not also the entity owning the power. Rather than correctly reporting the zero emission attribute in the MRR report of the entity that owns the electricity, the regulation requires that the first deliverer report the zero-emission renewable energy on their MRR report. This inappropriately distorts the emissions profile of the affected parties. (LADWP5)

Response: We disagree with LADWP's assertion that it is not a scheduling coordinator. We recognize LADWP as a scheduling coordinator, i.e., an entity that schedules power for delivery, for itself, and for BWP and GWP. We do not define "scheduling coordinator." LADWP correctly identifies itself as the first deliverer of power owned by GWP and BWP.

LADWP has reporting requirements pursuant to the MRR for electricity that it imports as a first deliverer, and it also must report other data as a retail provider, pursuant to the MRR. See response to Comments I-2, I-3, and I-4 for the role of LADWP as an agent for BWP and GWP. LADWPs comments about the "true emission profile" have no relevance to this regulation. LADWP has a compliance obligation for electricity for which it is the first deliverer, regardless of LADWP's "true emission profile."

Please see the first response in this (resource shuffling) section for our reasoning about a first deliverer's attestation. We believe that LADWP and all stakeholders should be able to determine if they have intentionally engaged in resource shuffling.

Renewable Portfolio Standard and RECs

Consistency with RPS

I-29. (multiple comments)
Comment: CEERT appreciates CARB's efforts to refine the treatment of imported electricity, and supports the revisions to the regulation. However, given the ongoing uncertainty around the requirements for imported electricity under the California Renewable Portfolio Standard, it is not yet possible to fully evaluate the fairness or soundness of the changes to section 95852(b). CEERT views the RPS and cap-and-trade programs to be loosely linked by the allowed use of RECs as a compliance tool in both programs. We strongly suggest that the ARB work in close coordination with the California Public Utilities as they develop a decision on the portfolio content categories and the California Energy Commission as they develop the RPS eligibility guidebook and regulations for the municipal utilities on the treatment of Renewable Energy Credits and imported electricity. Specifically, CEERT recommends that the ARB include a statement of intent to reevaluate and modify this section as appropriate, pending decisions by the CEC or CPUC, to ensure that policies of the three energy agencies are aligned and that the goals of the programs remain intact. (CEERT2)

Comment: Provisions related to renewable imports must be modified for consistency with the RPS. The MRR provides two scenarios under which an importer may claim a clean emission rate for imported power: (i) direct delivery from a renewable generator and (ii) through the RPS adjustment for renewable procurement that is firmed and shaped. In both cases, the regulation requires that the Renewable Energy Credits (RECs) associated with the renewable energy generation be retired/used for compliance with the RPS. This requirement would mean that an entity that wishes to claim either direct delivery or the RPS adjustment for renewable procurement would have to retire the associated REC in the same calendar year in which the REC was generated. Further, because the language pertaining to the RPS adjustment states the REC "must be used to comply", it suggests that the RECs that are retired and banked by a California retail provider for later compliance use cannot be used for an RPS adjustment. Both results are inconsistent with the RPS compliance flexibility provided under California's RPS law.

For directly delivered renewable energy, the regulation requires that "If RECs were created for the electricity generated and reported pursuant to MRR, then the RECS must be retired and verified pursuant to MRR." For the RPS adjustment, the regulation requires that "The RECs associated with the electricity claimed for the RPS adjustment must be used to comply with the California RPS requirements during the same year in which the RPS adjustment is claimed."

SB X1-2 allows RECs to be traded for three years after generation. After three years the RECs must be retired. Further, importers under the cap and trade program may be generators, marketers or load-serving entity. Generators and marketers of imported renewable energy may not be able to avail themselves of the cleaner emission rate because they are not the end-user of the RECs and cannot compel retirement.

While many of the details of implementation of SB X1-2 remain to be determined through CPUC and CEC proceedings, it would be inappropriate for CARB to prejudge the outcome or to adopt regulations in the cap and trade program that conflict with the RPS program, and therefore the modified regulation should clearly specify that the CARB regulations are not intended to conflict with the RPS compliance requirements or to reduce the compliance flexibility afforded in the RPS statute.

Per conversations with CARB staff, we understand that the requirement for REC retirement was added to the regulation to address two objectives: that renewable imports not be claimed for both an allowance retirement under the cap and trade program's Voluntary Renewable Energy set-aside and that there is a clear nexus between any claims to renewable energy imports under the cap and trade program and the RPS program. WPTF does not object to these goals, but believes they could be accomplished in a way that does not conflict with RPS Law nor restrict flexibility under the RPS program. Specifically, we recommend that the regulation be modified to make claims to imported renewable energy or the RPS adjustment contingent upon procurement of RECs, rather than reporting the REC"s for compliance. CARB can avoid potential double-counting with the VRE program simply be prohibiting the same energy from being claimed for both the RPS adjustment and the VRE program. This would be easily verified by requiring reporting of REC serial numbers under both the VRE and the RPS adjustment. Modify section 95852(b)(3) and (4) as follows:

(3) The following criteria must be met for electricity deliveries to calculate their compliance obligations based on an ARB facility specific emission factor specified pursuant to MRR section 95111 less than the default emission factor for unspecified electricity specified pursuant to MRR section 95111:
(A) Electricity deliveries must be reported to ARB and emissions must be calculate pursuant to MRR section 95111;
(B) The electricity importer must be the facility operator or have ownership or a written power contract, as defined in MRR section 95102(a) to the amount of electricity claimed and generated by the facility or unit claimed;
(C) The electricity must be directly delivered, as defined in MRR section 95102(a), to the California grid, and
(D) ~~If RECs were created for the electricity generated and reported pursuant to MRR, then the RECs must be retired and verified pursuant to MRR.~~ <u>If the electricity claimed is from an eligible renewable energy resource, the electricity importer must have ownership or contract rights to procure RECs associated with the claimed electricity or a contract to import the electricity on behalf of a California entity that has ownership or contract rights to procure RECS associated with the claimed energy.</u>

(4) RPS Adjustment. Electricity imported ~~or procured~~ by an electricity importer from an eligible renewable energy resource reported pursuant to MRR must meet the following conditions to be included in the calculation of the RPS adjustment:

(A)The electricity importer must have either:
(1) Ownership or contract rights to procure RECs associated with the electricity generated by the eligible renewable resource or
(2) Have a contract to import electricity on behalf of a California entity that has ownership or contract rights to procure RECs associated with the electricity generated by the eligible renewable energy resource, ~~as verified under MRR.~~
~~(B) The RECs associated with t~~The electricity claimed for the RPS adjustment must be imported ~~used to comply with California RPS requirements~~ during the same calendar year in which the RECs procured from the eligible renewable energy resource are generated; ~~RPS adjustment is claimed.~~
(C) The quantity of emissions included in the RPS adjustment is calculated as the product of the default emission factor for unspecified sources, pursuant to MRR, and the reported electricity generated (MWh) that meets the requirements of this section, 95852(b)(4).
(D) No RPS adjustment may be claimed for an eligible renewable energy resource when its electricity is directly delivered or claimed as Voluntary Renewable Energy.
(E) No RPS adjustment may be claimed for electricity generated by an eligible renewable energy resource in a jurisdiction where a GHG emissions trading system has been approved for linkage by the Board pursuant to subarticle 12. (WPTF3)

Comment: The Cap-and-Trade Regulation and MRR should be closely aligned with the 33 percent RPS, including consistent definitions. Rather than come up with different definitions, it would be more efficient for the regulated entities and the regulating authorities to provide consistent definitions for the same concepts. For example, the California Renewable Energy Resources Act will reward utilities that comply early by allowing them to apply excess procured electricity products to satisfy subsequent compliance periods under the law. However, under the proposed concepts of "resource shuffling" and "electricity imports" LADWP may be penalized for not actually delivering electricity that it took credit for in an earlier compliance period for SB2 (1X). Therefore, it is unclear whether LADWP will be rewarded for early compliance with the California Renewable Energy Resources Act, yet run afoul of Cap-and-Trade regulations. Another example is the definition of "eligible renewable energy resource" which "has the same meaning as defined in Section 399.12 of the Public Utilities Code." Because the RPS program is currently undergoing modifications, it is unclear if this cross reference includes the entire legislative section as it does not expressly indicate that other portions of section 399.12 are excluded. LADWP recommends that the cross reference be made to the California Energy Commission's RPS Eligibility Guidebook, rather than Section 399.12. Without clarification on this definition, inclusion of the entire Section 399.12 would include the definition of "retail seller" which is different from "retail provider" in that it expressly does not include publicly owned utilities. Additionally, section 399.12 does not include eligible renewable energy from incremental improvements at hydroelectric facilities as allowed under existing law (Public Utilities Code, section 399.12.5). The CEC Guidebook is the standard for RPS eligibility. These definitions should be more closely aligned to avoid confusion and potential conflicts in legal interpretation, especially given the unique role that ARB will have to establish penalties for enforcement of the 33 percent RPS for publicly owned utilities. (LADWP5)

Comment: Noble Solutions believes that ARB staff has been attentive to entities that are engaged in the importing of electricity into California, and has drafted modifications to the proposed regulations that address many of the concerns raised by these stakeholders. However, there remains an ambiguity in the proposed regulation at section 95852(b)(4)(B), which is proposed as follows:

> The RECs associated with the electricity claimed for the RPS adjustment must be used to comply with California RPS requirements during the same year in which the RPS adjustment is claimed.

This sentence appears to contemplate a direct linkage between compliance with the RPS statute and compliance with the GHG the program. While there is no question that these two laws are complementary—perhaps it is better to say that RPS compliance is one of the tools that can be used to achieve GHG objectives—they are still different programs administered by different agencies. Conflating the two does not serve the purposes of either.

To illustrate the point plainly, consider the following transaction. A reporting entity executes a firming and shaping contract calling for the import of 1000 MWh of energy and 1000 qualified RECs during Year 1. For GHG reporting and compliance purposes, the "RPS adjustment" would be claimed in the first year. However, RPS rules permit banking of RECs under certain conditions. It might be desirable for the reporting entity to hold these RECs for RPS compliance purposes until the second year. But as section 95852(b)(4)(B) is currently written, this apparently would not be permitted, since the RECs "used to comply with California RPS requirements" would not be used in the same year as the RPS adjustment was claimed.

Noble Solutions does not understand what GHG compliance purpose such a restriction can have. As long as the RPS adjustment is linked to a qualified import transaction in the same reporting year, it is completely irrelevant when—or even if—the RECs associated with that RPS adjustment are claimed for California RPS compliance purposes. It is simply not within the purview of ARB to specify how an entity complies with California RPS requirements. Clearly, there is a serious jurisdictional question presented, since section 95852(b)(4)(B), as drafted, usurps the prerogative of the California Public Utilities Commission to design the implementation rules—including the banking of RECs—under the RPS statute. Modify section 95852(b)(4)(B) as follows:

> ~~The RECs associated with t~~The electricity claimed for the RPS adjustment must be imported ~~used to comply with California RPS requirements~~ during the same calendar year in which the RECs procured from the eligible renewable resource are generated. ~~RPS adjustment is claimed.~~ (NAES2)

Comment: MSCG applauds the elimination of the requirement that "Replacement Electricity" (Substitute Power or Substitute Electricity in the latest draft) must originate from the same balancing authority. Related to the same issue, one additional flaw has come to our attention, regarding the calculation of the "RPS Adjustment" used for determination of emissions responsibility for imported electricity. Section 95852(b)(4) requires that RECs associated with the electricity claimed for the RPS adjustment must be used to comply with California RPS requirements during the same year in which the RPS adjustment is claimed.

This creates two problems. First, RECs are "bankable." So, it is likely that some RECs may not be used for compliance in the year that they are generated. If ARB requires use for compliance in the same year, there is a misalignment with state policy regarding use of RECs for Renewable Portfolio Standard purposes. Second, as a purely practical matter, the entity importing the power will, in many cases, not be the entity submitting the REC for compliance. Put another way, the importer in a typical "firming and shaping" deal will have no idea whether or not its customer submitted an associated REC for compliance in any given year.

The solution seems straightforward. Simply require that the associated REC be created (as verified by WREGIS) and imported into California (as verified by NERC E-tags) in the same Calendar year, as opposed to submitted for compliance. This should accomplish the underlying purpose of an annual "match-up" of associated renewable generation and substitute power occurs. This approach will meet the state requirement for eligibility for "firming and shaping" deals. (MSCG4)

Comment: Additionally, 3Degrees wishes to note the distinction between REC ownership and REC retirement. Currently, section 95852(b)(3)(D) requires the outright retirement of RECs pursuant to guidance in the MRR, a stipulation that decreases the liquidity of the renewable energy markets in California. While the retirement of the RECs associated with specified electricity imports is necessary to prevent double counting, ARB should maintain flexibility to allow trading of the REC within California boundaries. 3Degrees welcomes discussion with ARB staff on this issue. (3DEGREES3)

Comment: LS Power asks CARB take care to avoid limiting the flexibility provided for in the new RPS law which allows firming and shaping of renewable energy throughout the multi-year compliance periods. ARB should avoid imposing regulations that conflict with the RPS Program. LS Power is concerned that CARB's proposed rules regarding the treatment of power used to firm and shape RPS deliveries, particularly power used to deliver renewable energy credits (REC) into California at a time later than the production from the renewable resource, will conflict with provisions found in the new 33 percent RPS law. Specifically, new Public Utilities Code section 399.16(a)(6) provides a 36 month "shelf life" for RECs. Provisions in the CARB regulations would hinder the flexibility provided by the Legislature by imposing a current year delivery requirement to avoid a compliance obligation for power imported to deliver the REC (the RPS Adjustment mechanism).

This should be avoided. The implementation details for the RPS program are still under development at the CPUC and the CEC. It is critical for the developers, marketers and purchasers of RPS products, particularly those contemplating firmed and shaped transactions, to not lose the additional flexibility for delivery and multi-year compliance periods provided in the new 33 percent RPS law.

In conclusion, LS Power requests that in a board resolution, CARB identify the electricity importer definition as a specific topic that will be addressed in a subsequent rulemaking before the cap-and-trade program takes effect. LS Power also requests that the Board note the lack of clarity in the Resource Shuffling provisions and direct Staff to revise those provisions with further stakeholder input. LS Power requests that the Board amend the default emissions factor to be more consistent with the emissions factors adopted by other regulatory agencies and a better representation of generation within the WECC. Finally, provisions impacting the use of RECs under the RPS program must be revised to avoid truncating the flexibility provided for in the new RPS law. LS Power appreciates the opportunity to provide these comments, and looks forward to continuing its efforts with staff on these matters. (LSPOWER2)

Comment: The Utilities support the removal of the “Replacement Electricity” requirement. Although the Utilities are generally supportive of the new concept, “RPS Adjustment”, we have concern that it is difficult to follow and suggest removal of the RPS Adjustment altogether. Instead, the Utilities suggest that CARB consider simply applying an emission factor of zero for all imports related to RPS eligible generation. (MID4)

Comment: Iberdrola Renewables is very concerned with the CARB’s revised regulation’s requirements for qualification of the Renewable Portfolio Standard Adjustment (RPS Adjustment). The revised regulation requires an Electricity Importer to demonstrate that a Renewable Energy Credit (REC) was used for RPS compliance in the same year that the RPS Adjustment is claimed. This requirement appears to conflict with the current RPS rules which require an entity to demonstrate sufficient RECs to support firming and shaping transactions for a calendar year but do not require the REC to be retired in that same year. Similarly the RPS legislation passed in 2011, and the ongoing rulemaking implementing it, focuses entities on making retirements for multi-year compliance periods. The retirement targets a total number of RECs for the compliance period—not retirement quantity for a specific year. A cap and trade regulation requirement that reduces an importers flexibility to comply with the RPS is unacceptable and CARB must structure its regulation to be consistent with the broader California RPS program. Iberdrola Renewables requests the Board explicitly direct the CARB to enter into subsequent rulemaking to ensure the final regulation is aligned with the California RPS program and not in conflict. (IBERDROLA2)

Comment: CARB should utilize the Proposed Revision as the basis for reviewing the emissions obligations associated with renewable energy contracts, rather than the more onerous “replacement electricity” provisions found in the July 27 Modified Text that would have placed restrictions on the calculation of the compliance obligation based balancing authority boundaries that had no relationship to the actual production or delivery of the renewable resource. NCPA cautions, however, that the language should not place restrictions on ownership types, in order to ensure that none of the various interests in these renewable resources are precluded from utilizing the RPS adjustment. Likewise, this is the case with regard to the “contracts” to import electricity for the compliance entity set forth in section 95852(b)(4)(A)(2), the arrangements for delivery of the electricity may take different forms, and there should not be strict adherence to the term “contract,” as long as a legitimate arrangement exists between the parties. (NCPA)

Comment: NextEra appreciates the efforts of the California Air Resources Board (ARB) staff to date in the development of the regulations implementing the California Global Warming Solutions Act of 2006 (AB 32). As this is the final opportunity for stakeholders to submit formal written comments to ARB staff on this rule, NextEra would like to emphasize that overall the rule is an effective step toward establishing the framework to enable California to meet its GHG emissions reduction goals. In response to the proposed language changes released on September 12, 2011, NextEra supports the comments submitted by two of our trade groups; the Independent Energy Producers of California (IEP) and the Western Power Trading Forum (WPTF).

Highlighted below are several issues we feel must be addressed by ARB staff. Please refer to the comments submitted by IEP and WPTF on these issues. Specifically, the criteria for utilizing the “RPS Adjustment” for imported renewable energy are not consistent with the California Public Utility Commission (CPUC) RPS program. (NEXTERAENERGY3)

> **Response:** The first 15-day changes to the regulation contained provisions in section 95852 that allowed the replacement electricity needed for eligible variable renewable electricity to not result in a compliance obligation. Stakeholders claimed that we should recognize all procurements that meet RPS requirements as not having a compliance obligation under the cap-and-trade program. In the second 15-day changes to the regulation, we removed the requirements for replacement electricity, which applied only to variable renewable resources, to come from the same balancing authority. We replaced the provision with the RPS adjustment calculation pursuant to 95852(b)(4). The RPS adjustment results in an adjustment to a compliance obligation for a first deliverer’s covered emissions.
>
> Before making this recent change, we reviewed RPS compliance options with respect to the direction provided in AB 32 and chaptered in Health and Safety Code (HSC) section 38562(d). HSC section 38562(d)(1) requires us to ensure that the greenhouse gas emission reductions achieved are real, permanent, quantifiable, verifiable, and enforceable by the State board. ARB considered whether “avoided emissions” attributed to procurement of renewable energy (with bundled RECs) or attributed to tradable RECs (purchased without the underlying electricity) are quantifiable and enforceable. In addition, HSC section 38562(d)(2) requires that any reduction of greenhouse gas emissions used for compliance purposes, such as compliance offsets, must also be in addition to

any greenhouse gas emission reduction otherwise required by law or regulation, and any other greenhouse gas emission reduction that otherwise would occur.

We considered the RPS delivery arrangements, including tradable RECs paired with imported electricity, various firming and shaping arrangements that include procurement of the renewable electricity (and bundled RECs), and direct delivery as defined pursuant to MRR section 95102(a). We also considered relaxing the focus on direct delivery, to allow any electricity from the same balancing authority area or jurisdiction to be recognized as being from a specified source located in that balancing authority area. As suggested by stakeholders, we considered whether siting and transmission constraints should be factored into justification for an avoided emissions approach or a relaxed delivery definition for various facility types. Facility types included variable renewable resources (wind, solar, and run-of-river hydroelectricity) that generate electricity on an intermittent basis, all eligible renewable resources recognized by California's RPS program, all facilities that generate electricity from renewable energy, all resources recognized as zero GHG-emitting, or resources with emissions exempt from a compliance obligation.

Finally, we considered how various alternatives may be implemented to assure impartiality across all electricity importers, whether they are strictly marketers or are retail providers that also purchase and sell wholesale power.

ARB concluded that the RPS was not designed to adequately quantify avoided GHG emissions incorporated in RECs, or reduced emissions as required by AB 32. Factors that can complicate quantification of GHG reductions associated with renewable energy include whether a particular facility is located in a region that has an oversupply of electricity. Oversupply can dampen price signals relative to California that would otherwise produce GHG reductions through efficiency and conservation. Another factor is the uncertainty regarding the emissions profile of the actual electricity-generating facilities that stop operating, operate less often, or will not be built as a result of a particular renewable energy resource. These may be hydroelectricity resources with no covered emissions or newer natural gas plants with different efficiencies than those of older facilities. Finally, emissions leakage, which may occur when less-efficient out-of-state natural gas facilities provide firming and shaping to replace the out-of-state renewable energy that cannot be directly delivered, may cause less demand for electricity from more efficient in-state natural gas facilities.

We also considered the intent of the recently enacted legislation, SBX1 2, which requires 33 percent of total retail sales of electricity from utilities in California per year by December 31, 2020. SBX1 2 is on a path toward implementation through proceedings taking place at the California Public Utilities Commission and the California Energy Commission. The intent of the bill is to increase the amount of electricity generated from eligible renewable energy resources per year, so that amount equals at least 33 percent of total retail sales of electricity in

California by 2020. The RPS is designed to advance this important State policy, and we recognize that significant GHG emission reductions will occur as a result. For electricity that is procured from out-of-state facilities to meet the RPS compliance obligation of retail providers, but is not directly delivered into California, we decided that an RPS adjustment factor could be incorporated to reduce the compliance obligation. This approach maintains the rigor and consistency necessary for GHG emissions reporting and addresses stakeholders' concerns about additional cost of the RPS program.

We were concerned that the right to claim avoided emissions from out-of-state renewable energy resources is not as settled as commenters describe and would be unenforceable by us under a regional cap-and-trade program. A REC is not a compliance instrument ,and it does not contain a right to claim avoided emissions to comply with any GHG regulatory program. This is explained in the WREGIS Operating rules. RPS compliance mechanisms cannot guarantee that null power (electricity generated by a renewable energy resource and sold without the RECs) generated outside California would be assigned a GHG emission factor.

We also considered whether tradable RECs may be a workable mechanism to assign and track avoided emissions, but determined that they would act similar to an offset, but would only be available to the electricity sector. Tradable RECs do not meet the rigorous requirements for compliance offsets, intended to be available to all sectors, particularly additionality. The GHG emission reductions outside California that occur as a result of RPS compliance are not additional, since the purchase is required by California's RPS program. Many commenters take the position that all RPS-eligible procurement should also be eligible for an adjustment in their compliance obligation. We do not agree with this entire approach. We believe the appropriate way to think about renewable electricity is that most times it represents emissions avoided, rather than emissions reduced. Once a cap is in place, renewable electricity no longer reduces greenhouse gas emissions; it simply helps to meet the cap. Some commenters, such as SEMPRA, provide additional rationale for allowing for the use of tradable or RECs, unbundled from the underlying electricity, to the extent that tradable RECs qualify under the RPS. However, the cap-and-trade compliance obligation is based on source-based GHG emissions reporting and verification for emissions from electricity from specified and unspecified sources. The accounting simply cannot accommodate the tracking and calculation of avoided emissions. It is not necessary for this regulation, which regulates metric tons of GHG emissions, to be completely coordinated with the RPS, which is a program that tracks megawatt-hours of electricity generated represented by RECs.

When electricity is generated by a renewable resource and is directly delivered to California, then it is treated just like any other specified resource. These requirements are contained in section 95852(b)(3). The first deliverer must have a written power contract for electricity generated by the facility, and the electricity importer must report the delivery as a specified import. 3DEGREES requested clarity in regard to the reporting of RECs associated with specified electricity. In response, we require that, if RECs were created for the electricity generated and reported pursuant to the MRR, then the RECs must be retired and verified pursuant to the MRR. Electricity importers must be able to provide documentation for verification within 45 days following the June 1 reporting deadline that the RECs have been retired. If the electricity importer's verifier cannot confirm that the RECs are retired, the reporting entity will be in non-conformance, but the claim to the zero GHG emission factor (0 MT of CO_2e/MWh) remains valid. While we recognize the emissions profile of the imported electricity, REC retirement is needed to ensure that other GHG accounting programs that may assign emission attributes do not double-count any avoided emissions.

For eligible renewable electricity which cannot be directly delivered, we provide an adjustment for the procured electricity as long as it meets the requirements to take the RPS adjustment in section 95852(b)(4). There are various situations in which renewable electricity is not able to be directly delivered to California. Some commenters such as Noble Energy view this electricity as "firmed and shaped." However, we do not use that term. All electricity that is procured for the purpose of RPS must report to the MRR separately. In other words, if a specified or unspecified source is used to meet RPS delivery requirements, then the emissions will be reported pursuant to MRR under the requirements for reporting specified and unspecified sources. The megawatt-hours from the eligible renewable facility will also be reported. We will adjust down the first deliverer's compliance obligation for the megawatt-hours of the renewable electricity. The RPS adjustment applies to electricity procured, during the same data year from eligible renewable facilities to meet the requirements of California's RPS program. The equation for the calculation of the RPS adjustment that allows a reduction of covered emissions is based on the default emission factor for unspecified sources, pursuant to MRR. We require the same data year because our program is based on annual emissions reported to support the implementation of triennial compliance periods, in which there are annual surrender requirements. RECs associated with the RPS adjustment must be retired in order to claim the adjustment to the compliance obligation. Electricity importers must be able to provide documentation for verification. If we were to fully align with RPS delivery arrangements, which allow for RECs to be banked and traded for up to three years, then it is possible the cap-and-trade program could be allowing for an adjustment to a compliance obligation in a reporting year. A few years later, the REC could be sold to another utility and could be used again, whether for meeting the California RPS—which could also be attached to an cap-and-trade RPS adjustment that year—or could be used in another utility in another state to meet their RPS.

Noble Solutions' proposed modification cannot work because the RPS adjustment is for electricity that is not able to be directly delivered to California as a result of the characteristics of the renewable resource and the distribution system. We believe that it is clear that the RPS adjustment is calculated based on electricity generated at, and procured from, the eligible renewable energy resource during the same year that it is claimed for the adjustment. The MRR requires annual reporting, and the compliance obligation for a year is based on the equation. We are interested in the new NERC e-Tag/WREGIS renewable delivery verification function in the WREGIS system, to see if that could assist in the tracking of electricity that has already been assigned an adjustment under our program. ARB will be looking into this new functionality and will be determining in the coming year if it can assist in our data needs.

We note that NCPA wants to "ensure that none of the various interests in these renewable resources are precluded from utilizing the RPS adjustment" and recommends that the regulation not "place restriction on ownership types." We believe that it is critical that a first deliverer seeking to use the RPS adjustment be required to have ownership or contract rights to procure the electricity generated by the eligible renewable resource, or have a contract to import electricity on behalf of a California entity that has ownership or contract rights" to the same. These are the ownership and contract conditions to which the RPS adjustment is subject in the modified regulation. We believe that the word "contract" covers virtually all documentable legitimate arrangements for the exchange (including purchase or sale) of electricity between parties. We also believe that it would be imprudent for a California entity that has ownership or contract rights to the electricity generated by [a] renewable energy resource" to make an agreement with another first deliverer to deliver this electricity without a contract. A written contract may authorize the use of other forms of contracting (e.g., e-mail, telephone conversation) However, any of these types of contractual activity authorized by a written contract must necessarily be verifiable by, for example, a recording of a telephone conversation, a digital document exchanged between parties, or some other documentation sufficient to meet the MRR's verification requirements.

NCPA and PG&E would like us to remove section 95852(b)(4)(E), which contains a sunset clause for the RPS adjustment for purchases of eligible renewable electricity from jurisdictions that we have an established linkage, pursuant to subarticle 12. Because renewable electricity does not reduce GHG emissions in a capped jurisdiction, as discussed at length, we disagree and did not remove section 95852(b)(4)(E). California is in agreement with WCI that RECs have no place in GHG accounting, since they are not a measure of emissions. We make it clear that an RPS adjustment may not be claimed when the eligible renewable resource is located in a jurisdiction where a GHG emissions trading system has been approved for linkage by the Board pursuant to subarticle 12, consistent with treatment of electricity from eligible renewable facilities under California's cap. As mentioned previously, once a cap is in place, renewable electricity no longer reduces emissions; they avoid emissions and help to meet the cap.

In Comment I-30, SEMPRA claims that "the recent change to the rule creates an inconsistency between AB 32 and the recently signed SBX1-2," and that "[t]his inconsistency is at odds with the ARB's Scoping Plan." It is true that the Scoping Plan expected significant GHG reductions from a recommended new 33 percent RPS mandate. But as discussed elsewhere, RPS electricity does not always reduce GHG emissions. When California is capped, any single RPS project cannot reduce emissions below the cap, even though it would be much more difficult for California industry, including the electric sector, to meet the cap if the separate RPS mandate did not exist. This is not an inconsistency, but is in the nature of the early years of transition to an economy with a GHG emissions cap. Our responses to 15-day comments explain more about the cases in which renewable electricity does, or does not, reduce emissions. An adjustment to allow a first deliverer "credit" for RPS electricity that is not delivered means that some double counting may occur, we decided to recognize past investments in the RPS by the utilities through a limited RPS adjustment. This is because we recognize that, during the transition, it is helpful to recognize that utilities were required by law to invest in renewable electricity generation and that until the cap is in place, that generation is very likely to be accompanied by reduced need for emitting resource generation somewhere in the WECC.

We believe our regulation is as consistent and as aligned as possible with SBX1 2, at this point in time. SBX1 2, while not yet implemented by CPUC and CEC, phases down the use of renewable electricity that cannot be directly delivered, and purchases of RECs only without the underlying electricity (unbundled REC). Although 25 percent of a utility's RPS compliance obligation can be met with these so-called "category three" products in the RPS compliance period ending December 31, 2013, only 10 percent can be used associated with contracts executed after June 1, 2010, to be used after 2016.

CEERT suggests that ARB work with "the California Public Utilities" (we believe CEERT means the CPUC) and CEC as they develop decisions on "portfolio content categories." We will continue to work with CPUC and CEC. However, it is necessary, for reasons already discussed, for this regulation to treat renewable electricity differently than does the RPS. We do not necessarily expect CEC and CPUC to treat RPS eligible electricity the same as we do, because this regulation measures reductions in metric tons of GHG emissions, and the RPS program measures sales of MWhs of renewable electricity to consumers. RPS encourages new renewable electricity generation regardless of its effect on GHG emissions, while this regulation implements a cap on GHG emissions.

RECs Separate from the Electricity

I-30. Comment: ARB has made changes with respect to out-of-state renewable energy credits (REC) which will result in a reduction of greenhouse gases, meeting the purpose and intent of both the Renewable Portfolio Standard (RPS) and AB 32. However, the recent change to the rule creates an inconsistency between AB 32 and the recently signed 33 percent RPS mandate. Specifically, certain purchases resulting in transactions that meet RPS requirements will not count toward GHG reductions under AB 32. This inconsistency is at odds with the ARB's Scoping Plan for AB 32 which states, "For the purposes of calculating the reduction of greenhouse gas emissions in this Scoping Plan, ARB is counting emissions avoided by increasing the percentage of renewables in California's electricity mix from the current level of 12 percent to the 33 percent goal…" SoCalGas and SDG&E strongly recommend that ARB revise the language to not exclude tradable RECs, purchased apart from the electricity, from the RPS adjustment that reduces GHG emission compliance obligations. Because the Cap-and-Trade Regulation should be consistent with SB1x 2 ARB should modify the RPS adjustment to cover tradable RECs.

SDG&E and SoCalGas support ARB's modification to the Cap-and-Trade Regulation with respect to proposed changes in the second set of 15-day modifications regarding out-of-state renewables. The regulation now recognizes the greenhouse gas (GHG) reduction benefits of all of SDG&E's renewable contracts entered into to meet California's renewable goals and so will count the GHG benefits from those contracts and will not artificially tighten the cap.

The proposed language remains inconsistent with the RPS, however, insofar as it appears to disallow the counting of tradable RECs toward the RPS adjustment. As presented in the second set of 15-day modifications, the RPS adjustment requires a contract for the electricity and not just the REC. In contrast, under SB1x 2, unbundled RECs sold to a retail seller would meet RPS requirements, subject to limitations. Such transactions would result in a reduction of greenhouse gases, meeting the purpose and intent of both the RPS and AB 32. However, under the proposed Cap-and-Trade Regulation, RECs purchased apart from the electricity would not be treated as reducing GHG emissions. If ARB intended to align its regulation with the purpose and intent of SB1x 2, the Cap-and-Trade Regulation should be modified to allow tradable RECs to the same extent as SB1x 2. There is no justification for treating the RPS and AB 32 implementation differently, and to do so would undermine the ARB's own Scoping Plan and the Legislature's policies adopted in the RPS. Modify section 95852(b)(4) as follows:

(4) RPS adjustment. Electricity imported by an electricity importer or procured by an electricity importer from an eligible renewable energy resource reported pursuant to MRR, or RECs must meet the following conditions to be included in the calculation of the RPS adjustment:
(A) The electricity importer must have either:
1. Ownership or contract rights to procure the electricity or RECs generated by the eligible renewable energy resource; or
2. Have a contract to import electricity on behalf of a California entity that has ownership or contract rights to the electricity generated by the eligible renewable energy resource, as verified under MRR. (SEMPRA4)

> **Response:** We considered whether tradable RECs could be a workable mechanism to assign and track avoided emissions, but determined that they would act as *de facto* offsets only available to the electricity sector, and not a compliance instrument also available to other covered entities for use in meeting a compliance obligation. Tradable RECs do not meet the rigorous requirements for compliance offsets, intended to be available to all sectors, consistent with our regulation, particularly in terms of additionality. The GHG emission reductions that occur as a result of RPS compliance are not additional, since they are required by California's RPS program. Also, RPS allows for the procurement of the REC only, without the actual electricity. Allowing for the use of a REC only, without the electricity, would result in inaccurate accounting of emission reductions attributable to the electricity sector.

Ancillary Services

I-31. Comment: The RPS adjustment provisions should be better coordinated with the RPS program. The September 12th version of the regulation deletes reference to replacement electricity, and instead provides for an RPS Adjustment [section 95852(b)(4)]. For an importer to avoid the compliance obligation for ancillary services supporting a firming and shaping agreement, it must demonstrate that a REC was retired in the same year that the RPS adjustment is claimed. This limitation is one example of how the new requirements may be inconsistent with the current RPS program and potentially the rules under development at other public agencies, including the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC). IEP notes that the CPUC and the CEC are currently considering how to deal with these types of transactions for compliance with the 33 percent RPS and there is concern that the timeframe for retiring RECs between the RPS and the C&T program may not be the same. This inconsistency could detrimentally impact the intended functioning of the RPS markets. IEP therefore requests that CARB commit to evaluate how the RPS program matches up with CARB's cap-and-trade regulation and make changes over the next year, where necessary, to be consistent with the RPS program. (IEPA3)

> **Response:** Please see response to Comment I-30. In addition, we disagree with the comment regarding ancillary services. We do not agree that ancillary services are firming and shaping services. We believe these services are services provided by a host balancing authority area to maintain or manage the system.

MRR Reporting Requirements for RECs

I-32. (multiple comments)
Comment: Section 95852(b)(3)(D) (p. 91) refers to RECs from specified sources being "retired and verified pursuant to MRR." However, the MRR does not set out reporting and verification provisions relating to RECs. Nor does it need to. The existing REC tracking system endorsed by the California Energy Commission, the Western

Renewable Energy Generation Information System, collects all necessary information regarding RECs. ARB can access this information if required. Section 95852(b)(3)(D) should be amended to remove the reference to verification of RECs under the MRR. This change can be made without further 15-day public comment, as it is "nonsubstantial or solely grammatical in nature" for the purposes of section 11346.8(c) of the Government Code. Modify section 95852(b)(3)(D) as follows:

(D) If RECs were created for the electricity generated and reported pursuant to MRR, then the RECs must be retired.~~ and verified pursuant to MRR.~~ (SCPPA8)

Comment: As previously mentioned, 3Degrees welcomes this additional language to prevent double counting of the emissions characteristics associated with specified electricity imports from renewable energy facilities. However, 3Degrees suggests that ARB provided clarity as it relates to the reference to RECs "retired and verified pursuant to the MRR." The MRR does not provide guidance on REC retirement and verification. Including an explanation of this language would add clarity and prevent participant confusion. (3DEGREES3)

> **Response:** These comments fall outside the scope of the second 15-day changes to the regulation. These comments would be more appropriately posed under the MRR. However, pursuant to cap-and-trade regulation subsection 95852(b)(4)(B), RECs associated with the RPS adjustment must be retired in order to claim the adjustment. Under the MRR, electricity importers must be able to provide documentation for verification within 45 days following the June 1 reporting deadline that the RECs have been retired. If the electricity importer's verifier cannot confirm that the RECs are retired, the reporting entity will be in non-conformance, but the claim to the zero GHG emission factor (0 MT of CO_2e/MWh) remains valid. While ARB recognizes the emissions profile of the imported electricity, REC retirement is needed to ensure that other GHG accounting programs that may assign emission attributes to RECs do not double-count any avoided emissions.

I-33. Comment: A TL (transmission loss) factor must be applied to the RPS adjustment. As noted above, ARB has proposed a TL of 1.02 to imported electricity from unspecified and specified sources to account for transmission losses when it is measured at the first point of receipt in California rather than the busbar. ARB has not included such a TL in the RPS Adjustment calculation. Applying a TL factor to imported electricity implies that the emissions reported for replacement electricity (imported to satisfy RPS requirements), will be adjusted upwards by the TL. As with the QE Adjustment calculation, not applying the same TL factor to the RPS Adjustment will create an unfair inconsistency that could lead to unintended consequences. Without the TL, the RPS Adjustment will always be lower, by the 2 percent adjustment factor, than the GHG emissions calculated for imported RPS-eligible replacement electricity. Because the GHG emissions credit calculated as the RPS Adjustment should completely offset the GHG emissions of the imported electricity that qualifies for the RPS Adjustment, ARB should apply the TL factor to the RPS Adjustment. (SCE4)

Response: This comment falls outside of the scope of the second 15-day changes to the regulation. However, we do not agree with SCE that the transmission line loss factor needs to be incorporated into the RPS adjustment in this regulation. This comment would be more appropriately addressed within the MRR. Section 95852(b)(1)(B) refers to the MRR for calculation of the RPS adjustment. Transmission losses are factored into the reporting of electricity, for which the RPS adjustment is provided. These requirements are contained in the MRR. In the MRR, transmission losses are included in the RPS adjustment factor when the megawatt-hours (MWh) are procured at the busbar of the renewable energy resource. Otherwise, ARB assumes that any transmission losses that are additional to the MWh procured are made up by GHG-emitting resources.

Linking Issue

I-34. (multiple comments)
Comment: While NCPA supports the inclusion of the RPS adjustment, the current proposal to automatically sunset the use of the RPS adjustment upon linking (set forth in section 95852(b)(4)(E)) should be removed. While the Cap-and-Trade Program will undoubtedly benefit from an increased number of trading partners, it is going to be necessary for CARB and stakeholders to carefully examine aspects of the California program that will be impacted by linking. Accordingly, the appropriate time to review and analyze how the RPS adjustment should be addressed when linking with a partner jurisdiction is during that rulemaking process, and until that process is complete, there should be no cloud cast over how a compliance entity's RPS adjustment will be calculated in any given year. Treatment of the RPS adjustment should be included in the list of issues reviewed in the process of the subarticle 12 rulemaking specifically addressing linking, and accordingly, section 95852(b)(4)(E) should be stricken in its entirety at this time. (NCPA4)

Comment: PG&E appreciates the modifications to section 95852 that establish a mechanism to account for the GHG reductions associated with out of state RPS eligible resources. We believe a mechanism like this is crucial to ensure that California is able to account for the full GHG reduction benefits of the State's renewable programs. We remain concerned however with section 95852(b)(4)(E) that states that the RPS adjustment would not be allowed if a renewable resource is located in a jurisdiction which links with California's cap-and-trade program in the future. We understand ARB's intent to prevent double counting the GHG attributes of the renewable facility, however this prescriptive approach would prevent Californians from receiving credit for renewable investments in which the environmental attributes were conveyed to them contractually, solely to the fact that the state opted to develop a cap-and-trade program. As ARB has yet to determine whether and to what extent it will link with other jurisdictions and the rules under which linkage may occur, PG&E believes it is premature to disqualify out-of-state RPS eligible projects from such jurisdictions at this time. Accordingly, we recommend deleting the current language and inserting the following:

> (E) ARB will re-assess the subject of RPS adjustment if the underlying renewable resource becomes part of a linked jurisdiction in the future. (PGE5)

I-35. Comment: The Utilities do not believe that section 95852 (b)(4)(E) is necessary. As set forth under Subarticle 12, CARB will undergo a separate and distinct rulemaking each time linkage to another jurisdiction is considered. Then, and only then, should changes to the RPS Adjustment be considered. (MID4)

> **Response:** We did not make the requested change, because renewable electricity does not reduce GHG emissions in a capped jurisdiction. California is in agreement with WCI that RECs have no place in GHG accounting, since they are not a measure of emissions. We make it clear that an RPS adjustment may not be claimed when the eligible renewable resource is located in a jurisdiction where a GHG emissions trading system has been approved for linkage by the Board pursuant to subarticle 12, consistent with treatment of electricity from eligible renewable facilities under California's cap. As mentioned previously, once a cap is in place, renewable electricity no longer reduces emissions; they avoid emissions and help to meet the cap.

Renewable Portfolio Standard – Legal Arguments

I-36. (multiple comments)
Comment: The renewable portfolio standard adjustment includes a potentially fatal flaw that can be easily fixed. Powerex understands that the RPS adjustment provisions are critical to ensure that the zero-emission components of renewable energy are properly counted under the RPS, the MRR and the Cap-and-Trade Rule. Powerex therefore supports the inclusion of some form of RPS Adjustment in the Cap-and-Trade Rule. However, as currently drafted, the RPS Adjustment is at risk of legal challenge on two grounds.

First, the RPS Adjustment may impermissibly intrude upon the jurisdiction of FERC. The Federal Power Act ("FPA"), 16 U.S.C. sections 791-828c, gives FERC exclusive jurisdiction over sales of electricity at the wholesale level in U.S. interstate commerce, and over the interstate transmission of electricity. 16 U.S.C. 824(b); *Duke Energy Trading & Marketing, LLC v. Davis*, 267 F.3d 1042 (9th Cir. 2001); *State of Cal. v. Dynegy, Inc*., 375 F. 3d 831 (9th Cir. 2004). This jurisdiction preempts other federal or state agencies from taking any action that would encroach on matters entrusted by Congress to FERC alone, including matters such as the justness and reasonableness of rates and charges of wholesale power sellers, the use of interstate transmission capacity, and, most important here, the operation of interstate power markets, including review of any action or conduct that could result in undue discrimination against, or undue preference to, a market participant.

In its currently-proposed form, the RPS Adjustment could constitute impermissible discriminatory treatment of imported power. Specifically, the proposed RPS Adjustment methodology at section 95852(b)(4) of the Cap-and-Trade Rule that requires the associated RECs to be used to comply with California RPS requirements improperly restricts the low carbon intermittent generation that can be delivered and credited to those entities under contract to deliver RPS power to California load serving entities (LSE). This has the practical effect of granting an undue preference to the California LSEs, and unduly discriminating against first deliverers of imported power into the state that do not have RPS contracts with a California LSE. In addition, by limiting the low-carbon intermittent generation to “eligible renewable energy resources” as defined in section 399.12 of the Public Utilities Code, it also appears that the RPS Adjustment would interfere with the flow of certain power deliveries in interstate commerce in favor of California’s local interests. Shaping of intermittent generation is inherently incident to sales of electricity at the wholesale level in interstate commerce. As a result, the RPS Adjustment, as currently drafted, falls plainly within FERC’s FPA jurisdiction, both because of its impact on the movement of wholesale electricity across California’s border and its undue discrimination in favor of California LSEs.

Second, the restriction of the RPS Adjustment to California LSEs makes it vulnerable to a Commerce Clause challenge. Specifically, by limiting the RPS Adjustment to California LSEs, the Cap-and-Trade Rule discriminates against interstate commerce in favor of local interests in much the same way as Louisiana’s first use tax on natural gas pipelines crossing the state did, a regulation that was struck down as unconstitutional by the United States Supreme Court in *Maryland v. Louisiana*. 451 U.S. 725 (1981). FPA preemption and constitutional challenges under the Commerce Clause could pose serious threats to the RPS Adjustment and thus to the Cap-and-Trade Rule itself. This is unfortunate, as the objective of the RPS Adjustment is not discriminatory; rather, it is to ensure the proper accounting of the zero-emission components of renewable energy. Fortunately, protecting the RPS Adjustment from these challenges requires only minor changes to the proposed regulatory text. (POWEREX2)

Comment: The definition of the term “eligible renewable energy resource,” as it is used in section 95852(b)(4), should be expanded to include sources outside of the RPS program. This not only avoids a characterization of the RPS Adjustment as discriminatory in favor of local interests, it wisely expands the pool of resources available to California for meeting its GHG reduction goals. In creating the RPS program, California had various reasons for excluding certain categories of renewable energy sources from its scope. However, those reasons are independent of the sources’ carbon intensity. There are numerous valid, high-quality renewable energy sources that are not part of the RPS program but are excellent sources of emissions-free electricity for the state. To make the requisite change, Powerex suggests revising section 95802(a)(88) of the Cap-and-Trade Rule to include ARB’s previously proposed definition of “variable renewable resource.” The change would have the effect of expanding the definition—and, thus, the scope of the RPS Adjustment—to include numerous small hydroelectric facilities throughout the Western Interconnection that are not currently eligible renewable energy resources. At the same time, it avoids any circumvention of ARB's limitation on resource shuffling because the MRR already requires that renewable energy facilities be new, be repowered, or have a historic relationship with California. *See* MRR section 95111(g)(4). Modify section 95802(a)(88) as follows:

(88) "Eligible Renewable Energy Resource" has the same meaning as defined in Section 399.12 of the Public Utilities Code, as well as run-of-river hydroelectric, solar, or wind energy that requires firming and shaping to meet load requirements. (POWEREX2)

Comment: Expand the RPS Adjustment to allow the retirement of RECs outside of the RPS Program. To extend the RPS Adjustment to non-RPS sources, section 95852(b)(4) must be revised to allow entities that do not have RPS obligations to retire RECs. This can be achieved by creating an option to use an ARB REC retirement account. Under the "retirement account" option proposed here, market participants would set up ARB-specific retirement accounts in the Western Renewable Energy Generation Information System (WREGIS) that are associated with imported power. They would have to show evidence of delivery into the state in the same manner as required under the RPS program, and then retire the associated REC into a WREGIS "California ARB Retirement Account." This is exactly the same process that would be used by entities with RPS obligations, but instead of using the RECs to satisfy the RPS, the RECs would be retired into the WREGIS ARB Retirement account. WREGIS is a robust platform that has a sufficient level of integrity to allow ARB to be certain that a renewable was shaped and delivered into the state and that the REC associated with the RPS adjustment was actually retired. Setting up a WREGIS ARB retirement account would be a simple process that is already enabled in the current WREGIS configuration that could be accomplished simply by means of an ARB policy direction to users of WREGIS (i.e., electricity deliverers and their verifiers.) The RECs would be verified by through the ARB annual reporting and verification process in exactly the same way as if the REC had been retired for RPS purposes. Modify section 95852(b)(4)(B) as follows:

> (B) The RECs associated with the electricity claimed for the RPS adjustment must be <u>either retired into a dedicated California Air Resources Board retirement account operated by the Western Renewable Energy Generation Information System or</u> used to comply with California RPS requirements during the same year in which the RPS adjustment is claimed. (POWEREX2)
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> **Response:** We do not agree that the RPS adjustment would be preempted by the FPA. The Supremacy Clause of the United States Constitution declares unlawful state laws that "interfere with, or are contrary to," federal law. *Hillsborough County, Fla. v. Automated Med. Labs., Inc.,* 471 U.S. 707, 712 (1985) (quoting *Gibbons v. Ogden,* 22 U.S. (9 Wheat.) 1, 211 (1824)); see also U.S. Const. art. VI, cl. 2. Preemption analysis starts "with the assumption that the historic police powers of the States were not to be superseded by the Federal Act unless that was the clear and manifest purpose of Congress." *Rice v. Santa*

Fe Elevator Corp., 331 U.S. 218, 230 (1947). "[T]he purpose of Congress is the ultimate touchstone of preemption analysis." *Cipollone v. Liggett Group,* 505 U.S. 504, 516 (1992) (internal quotation marks omitted). Federal law can preempt state law in three ways. First, Congress may expressly preempt state law. Second, preemption may be inferred where Congress has occupied a given field with comprehensive regulation. Third, a state law is preempted to the extent that it actually conflicts with federal law. An "actual conflict" exists when "'compliance with both federal and state regulations is a physical impossibility[.]'" *Automated Med. Labs., Inc.,* 471 U.S. at 713.

A preemption claim involving state actions that conflict with the Federal Power Act ("FPA") are predicated on the Supremacy Clause. See *Duke Energy Trading & Mktg., L.L.C. v. Davis,* 267 F.3d 1042, 1055 (9th Cir. 2001). The FPA grants to FERC "'exclusive authority to regulate the transmission and sale at wholesale of electric energy in interstate commerce.'" *Transmission Agency of N. Cal. v. Sierra Pac. Power Co.,* 295 F.3d 918, 928 (9th Cir. 2002) ("TANC") (quoting *New England Power Co. v. New Hampshire*, 455 U.S. 331, 340 (1982)). Through the FPA, "'Congress meant to draw a bright line easily ascertained, between state and federal jurisdiction …. This was done in the Power Act by making [FERC] jurisdiction plenary and extending it to all wholesale sales in interstate commerce except those which Congress has made explicitly subject to regulation by the States.'" *Nantahala Power & Light Co. v. Thornburg,* 476 U.S. 953, 966 (1986) (quoting *Fed. Power Comm'n v. S. Cal. Edison Co.,* 376 U.S. 205, 215-16 (1964)).

When enacting the Federal Power Act, Congress gave no indication that it intended to preempt state environmental programs such as greenhouse gas regulations. The regulation here is designed and intended to regulate greenhouse gas emissions in California and is not intended to regulate the rates, terms or conditions of sales of electric energy in interstate commerce. Therefore, the regulation was not expressly preempted.

"Field preemption occurs when the federal statutory scheme is sufficiently comprehensive to infer that Congress left no room for supplementary regulation by the states." *Gadda v. Ashcroft,* 363 F.3d 861, 869 (9th Cir. 2004). "When the federal government completely occupies a given field or an identifiable portion of it . . ., the test of preemption is whether 'the matter on which the State asserts the right to act is in any way regulated by the Federal Act.'" *Pac. Gas & Elec. Co. v. State Energy Res. Conservation & Dev. Comm'n,* 461 U.S. 190, 212-13 (1983) (quoting *Rice v. Santa Fe Elevator Corp.*, 331 U.S. 218, 236 (1947)).

One purpose of the federal statutory scheme concerns the reasonableness of interstate power rates and nondiscriminatory access to interstate power transmission. In contrast, California's purpose for enacting AB 32 was to reduce emissions of greenhouse gases, and we are proposing to regulate the environmental impacts of electric generation and consumption. The FPA's regulation of wholesale sales does not cover the environmental impacts associated with electricity generation and consumption. Commenter asserts that certain definitions in the regulation may impact the wholesale electricity market, but has not specified how such definitions could result in regulation by ARB of the wholesale electricity market. That some part of the regulation could indirectly affect the electricity market does not demonstrate that the provision will result in regulation of wholesale electricity sales, such as setting prices or establishing conditions for participation in the wholesale electricity market. Therefore, this regulation is a separate field related to the regulation of greenhouse gas emissions unrelated to the rates or access to power transmission.

If it is impossible to comply with both state law and federal law, then the state law is preempted. See *Gade v. Nat'l Solid Waste Management Ass'n,* 505 U.S. 88, 108 (1992). Commenter has not indicated that it would be impossible to comply with the regulation and federal law. Because the regulation here relates to greenhouse gas emissions and does not purport to regulate wholesale electric energy sales, we do not believe that a conflict exists.

Moreover, the FPA leaves room for state environmental regulation. Indeed, 16 U.S.C. section 824(a) states: "Federal regulation . . . [under the FPA extends] only to those matters which are not subject to regulation by the States." This broad savings clause supports the conclusion that because air pollution is subject to regulation by the States, and not by the FPA or FERC, state regulation of GHG emissions caused by the generation and consumption of electricity is not preempted by the FPA, but may be regulated by the States. While such GHG regulation may have some impact on the wholesale prices paid for electricity, it is no more preempted by the FPA than state regulations limiting the amount of other pollutants that may be emitted by electric power plants—that may affect the cost of generating electricity and therefore indirectly affect the price of wholesale electricity. For these reasons, we do not believe the FPA preempts this regulation.

Regarding alleged discrimination, while the RPS Adjustment requires the retirement of RECs for compliance with the California RPS, any low carbon intermittent generation that can be delivered to California will not have a compliance obligation (unless GHG emissions with a compliance obligation are emitted in the generation of the intermittent low carbon electricity). Currently, there are limited circumstances under which intermittent power can be delivered across balancing authorities, but conditions for these circumstances are rapidly changing. For example, only recently has direct delivery through a dynamic transfer agreement been allowed into California BAAs. However, there are several kinds of these arrangements that are, or may soon, be available for use in importing intermittent electricity to California. Another way of providing direct delivery may be to aggregate sets of wind and solar power to produce a statistically valid firm schedule. Firming with non-renewable power could be used when needed for the schedule, subject to a compliance obligation, but there need be no obligation (if there are zero emissions) during the hours in which firming or shaping is not needed. Although Powerex alleges that “shaping is inherently incident to sales of electricity at the wholesale level in interstate commerce” this is not the case for dynamic transfer agreements. We note that the RPS adjustment is a transitional provision that will no longer have effect when California is linked to other jurisdictions pursuant to Section 12.

Because any first deliverer can use the RPS adjustment (provided they can show that RECs have been used for compliance with the California RPS), all first deliverers are treated uniformly. We note that only the first deliverer, which for imported electricity is the electricity importer, can use the RPS adjustment. Foreseeing the likelihood that LSEs would assist their counterparties in making use of the adjustment that could not be used by the LSE, section 95852(b)(4)(A)(2) allows for first deliverers to use the RPS adjustment even if they do not have ownership or contract rights to the electricity generated, if they have a contract to import the electricity on behalf of a California entity. Practically speaking, this is expected to cover all imported electricity that is RPS-eligible.

Commenter asserts that the RPS adjustment discriminates in favor of local interests, similar to the first-use tax in *Maryland v. Louisiana,* 451 U.S. 725 (1981). However, unlike the first-use tax imposed in *Maryland v. Louisiana,* the regulation here makes the RPS adjustment available to all first deliverers. The first-use tax in *Maryland v. Louisiana* included exemptions and credits that were available only to in-state uses, but here the RPS adjustment available to all first deliverers. We do not agree that the RPS adjustment discriminates between California and non-California first deliverers.

We did not expand the definition of “eligible renewable energy resource.” We note that a renewable generator located anywhere within the WECC can be considered an “eligible renewable energy resource”, and in many cases, a renewable resource that meets the requirements of other RPS programs will also meet the California requirements. This defined term does not favor California renewable generators, because eligibility is available to renewable generators located anywhere within the multi-state Western Interconnection.

The current RPS definition of “eligible renewable energy resource” provides the types of generating facilities that have been determined in the RPS program to have renewable attributes. Commenter proposes appending the definition of “eligible renewable energy resources” with resource types that have not been determined to be renewable. Doing so would contravene the existing statutory definition and create regulatory inconsistencies. Therefore, we did not make the proposed amendment. Accordingly, we also did not allow use of RECs for the RPS adjustment if they are not used to comply with California’s RPS.

As noted above, there is no discrimination among first deliverers; California and non-California deliverers alike must demonstrate the use of RECs for compliance.

Voluntary Renewable Energy

Reserve Account Cap Section 95831

I-37. (multiple comments)
Comment: In numerous past submissions to ARB, REMA has encouraged ARB to avoid placing a cap on the total allowances for the VRE Reserve Account. Such an inflexible cap would place an artificial ceiling on the growth of the voluntary market for renewable energy, while an annual adjustment would provide flexibility and encourage additional demand for VRE purchases. However, should ARB decide to maintain its proposed VRE allowance cap, REMA strongly recommends clarifying language in section 95870(C) ("Disposition of Allowances") that describes VRE allocations for under and over subscription scenarios outlined below. (REMA3)

Comment: As stated in previous comments, 3Degrees urges ARB not to adopt a pre-determined cap and to allow the budget adjustment to be determined solely by the ex-ante estimate of need based on demonstrated demand. This will send a clear market signal and promote the continuing future growth of voluntary renewable energy purchases. Should ARB decide to pursue a cap on the number of allowances that can be placed in the holding account, 3Degrees strongly recommends that the cap be subject to annual review and adjustment rather than at the start of each compliance period, or that an automatic review be triggered whenever demand exceeds the cap for two years in succession. (3DEGREES3)

Response: This comment falls outside of the scope of the second-15 day changes to the regulation. There were no changes proposed in sections 95831(b)(6). The language describing the Voluntary Renewable Electricity Account was not subject to public comment under the second 15-day changes to the regulation. Because the comment falls outside of the scope of the notice, no further response is required. However, we acknowledge 3Degrees, REMA, and others' concern regarding a cap on the pool of allowances and the potential for this to affect funding of renewable generators. As mentioned in the first 15-day changes to the regulation, there are a limited amount of allowances available for this purpose. The set-aside account is a form of transitional assistance for the voluntary sector. We understand the high cost of renewable electricity and the concern expressed by the voluntary sector to compete with the demand to meet RPS. However, our goal is to transition to 100 percent auction. To that end, it will be necessary for the voluntary sector to eventually participate in the program by registering as a voluntarily associated entity, and to purchase and retire allowances on behalf of the voluntary contributions.

VRE Program Timing

I-38. Comment: The Utilities continue to have concerns with the inclusion of a Voluntary Renewable Energy (VRE) set-aside program. As stated in our previous comments, the Utilities believe that a VRE market should only be considered after both the 33 percent Renewable Portfolio Standard (RPS) and the cap-and-trade programs are underway as the Utilities believe the VRE market will act in direct competition with the RPS market. The Utilities believe that delaying the start of the VRE market until 2014 is a start in the right direction; however, the Utilities suggest that additional stakeholder discussions be held in the interim to fully examine the impacts that this program will have on both the cap-and-trade and RPS markets. (MID4)

> **Response:** These comments are outside of the second 15-day changes to the regulation. However, as explained in first 15-day changes to the regulations, we do not agree with MID. The purpose of the VRE program is to remove the excess allowances for generation provided by the voluntary sector. The delay in the commencement of allowance retirement is to reflect the change in the year that allowances will be deposited into the Voluntary Renewable Electricity Account pursuant to section 95870(c). This change was made to accommodate the change in the first compliance year to January 1, 2013, and was changed to directly delay the commencement of the VRE program.

True-up/Rollover

I-39. (multiple comments)
Comment: REMA recommends that ARB include language in section 95870(c) that clearly outlines the allocation process in the case that the VRE Reserve Account is under-subscribed. In this scenario, unused allowances would be rolled-over into future compliance years to account for years when the VRE allowance supply exceeds demand. This, at the very least, will create a slim buffer to allow for VRE market growth in the succeeding program years. Under no situation should allowances designated for the Reserve Account be released into the general pool for compliance purposes; to increase its contribution to deployment of clean, renewable energy, the voluntary markets requires certainty in allowance allocations. This rollover of allowances into future years would strike a compromise between the competing policy cap vs. no cap VRE options. A periodic review and adjustment prior to the start of each compliance period would improve the oversight of the program; several Regional Greenhouse Gas Initiative (RGGI) states have adopted a similar provision. (REMA3)

Comment: REMA proposes that ARB provide clarifying language in section 95870(c) for the potential scenario of VRE Reserve Account over-subscription. Should requests for allowance retirement exceed the remaining reserve pool, REMA recommends that allowances be divided and retired equally among all qualifying applicants, such that each MWh receives the same carbon value. (REMA3)

Comment: As stated previously, 3Degrees urges ARB not to adopt a pre-determined cap and to allow the budget adjustment to be determined solely by the ex-ante estimate of need based on demonstrated demand. Should ARB decide to cap the number of allowances that can be retired each year, 3Degrees strongly recommends that the language in this sub-section be amended such that:

- In the case that demand for VRE allowances exceeds supply in a given year, ARB should distribute and retire VRE allowances distribution equally among qualifying MWhs and/or RECs. As written, the proposed regulation is unclear on this point.
- In the case of demand for VRE allowances for not equaling supply, then ARB should roll over excess allowances into future compliance years. This, at the very least, will create a slim buffer to allow for VRE market growth in the succeeding years. (3DEGREES2)

Comment: While section 95841.1 addresses many of the details necessary to effectively operate a VRE set aside, the one key item missing is how to account for oversubscription. CARB should outline exactly what will happen if the number of allowances requested for the VRE set aside in a given year exceeds the size of the set aside specified in section 95870(c). These details are necessary in order to provide more certainty and less risk to market participants in the event of oversubscription. The preferable solution is to follow the RGGI Model Rule, and "true up" allowances at the end of each compliance period. In this scenario, a predetermined amount of allowances are taken out of circulation at the beginning of the compliance period. At the end of the period, if the number of allowances requested for the voluntary market exceeds the set aside amount, then the appropriate number of allowances are taken out of circulation in the subsequent compliance period. Having a truing up mechanism reduces the risk that there won't be enough allowances for all voluntary sales in a given year, thus providing more market certainty and aiding in the growth of renewable energy capacity in California. If it is not possible to exceed the amount prescribed in section 95870(c), it is important that CARB specifies exactly how the limited allowances will be retired on behalf of VRE market participants (i.e. will they be retired for VRE market participants on a first-come first-served basis, or will they be distributed equally among VRE market participants on a MWh or REC basis). (KUSTIN17)

Response: These comments fall outside of the scope of the second 15-day changes to the regulation. The only changes proposed to section 95870(c) was to accommodate the change in the date that allowances would be deposited into the account, due to the change in the adjustment of the first compliance period. The language describing the amount and dates for allowances to be deposited into the Voluntary Renewable Electricity Account was not subject to public comment under the second 15-day changes to the regulation; therefore, no further response is required. However, we acknowledge the concerns expressed by REMA and others regarding what will happen if the account becomes fully subscribed and there are not enough allowances to cover all of the requests. Again, as described above, one of the goals of our program is to transition to 100 percent auction. Therefore, the design of the program does not support depositing additional allowances into the account. We will monitor the demand to retire allowances against the expected demand, and growth in demand, from the voluntary renewable electricity market. If we determine in future years that demand is exceeding our expectations, we will work with stakeholders to determine the best way to parse out the remaining allowances across all applicants in the remaining compliance period, if needed.

Some comments, such as the comments submitted by REMA and the Coalition, suggest that we include language regarding what happens to allowances if there are remaining allowances at the end of the year or compliance period. We do not include language that would parse out allowances into specific compliance periods for use within that compliance period, but instead have created a "pool" of allowances. The first compliance period allowances will be deposited, and each budget year allowances will continually be deposited according to the schedule outlined in section 95870(c). The allowances will remain in the account until they have been requested to be retired pursuant to the requirements outlined in section 95841.1. We do not include provisions for allowances to be accessed by any other participants, nor for the allowances to be accessed by the Executive Officer for use in the reserve account, or for compliance purposes, as some commenters suggested.

On-Line Date

I-40. (multiple comments)
Comment: Earlier in our comments, REMA noted the improvement to section 95841.1's online date for eligible renewable energy generation. The proposed online date of July 1, 2005 is more inclusive of existing renewable generation than previous iterations of the regulation, but a revised 15-year rolling window would accomplish two goals that the July 1, 2005 date would not. First, it would encourage additional Californian voluntary market participants through broader availability of credible, national renewable energy products from existing renewable energy producers. Voluntary green power sales provide generators an important source of revenue, and the 2005 date would reduce green power products available. Second, the 15-year rolling window would deter Californian utilities from looking towards out-of-state renewable energy generators to meet increased green power demand. Many state utilities offer their customers green power products, and efforts to bolster voluntary demand through the VRE's Reserve Account should support existing Californian green power generation. Two renewable energy industry leaders, the Environmental Protection Agency's (EPA) Green Power Partnership Support (GPP) and the Center for Resource Solutions (CRS) support the 15-year rolling window online date. REMA encourages that ARB consider this revision in the additional round of public input. (REMA3)

Comment: 3Degrees wishes to express its support for the inclusion of a generator online date. However, this date is inconsistent with the new date for the voluntary renewable energy market. The voluntary renewable energy market is a national market with an established 15-year rolling online date. By disallowing facilities with online dates prior to 2005 to qualify for the voluntary renewable energy set aside, many generators based in California would be excluded from participating in this national market. Although 3Degrees understands ARB's rational for its choice of July 1, 2005, we encourage the use of an online date that conforms to the standards already in use by the voluntary market. (3DEGREES2)

Comment: Section 95841.1(a) stipulates that only generation from facilities that served load after July 1, 2005 should be eligible for the VRE set aside. We strongly urge CARB staff to reconsider this date, as it is inconsistent with the established new date for the voluntary renewable energy market. The use of this arbitrary cutoff date would exclude a large portion of the renewable energy capacity currently serving the voluntary market in California, resulting in a reduction in environmental benefits currently supported by voluntary customers, removing an important source of revenue for these generators, and negatively impacting the clean energy industry in California.

The voluntary renewable energy market is a national market with an established 15-year rolling online date. Both the U.S. Environmental Protection Agency's Green Power Partnership and Green-e Energy employ this new date. By disallowing California facilities with online dates prior to 2005 to qualify for the VRE set aside, many renewable energy facilities based in California would be excluded from participating in this national market.

Should CARB keep the 2005 new date, approximately half of California capacity selling into the voluntary renewable market would no longer be able to participate in this national market. This figure includes all biomass, geothermal and landfill gas facilities, and half of the wind capacity in California that currently participates in the national voluntary market. These are generators that anticipated REC revenue from the voluntary market in order to be built, and by using a 2005 new date they would no longer receive this revenue.

We suggest not setting an arbitrary new date that puts California capacity at a competitive disadvantage compared to the rest of the U.S. If CARB moves forward with the 2005 date, REC providers both in California and nationally would turn to out-of-state RECs for their green power products, and the role of California generators in this market would be diminished. This would particularly impact California utilities that offer their customers green electricity, as they tend to own their own generation capacity or buy renewable energy generated within the state. (KUSTIN17)

> **Response:** These comments fall outside of the scope of the second-15 day changes to the regulation. There was no change noted to section 95841.1(a) in the Second 15-day Change Notice for the on-line date for eligible electricity, and was therefore not subject to public comment under the Second 15-Day Change Notice. However, we acknowledge the concerns expressed by the Coalition, REMA, and 3 Degrees regarding the disadvantage that may fall upon the

generators, or investments made to support the development of the facility, that came on-line prior to 2005. This on-line date coincides with the year in which out-of-state renewable facilities are eligible under the RPS. It also coincides with the date of Executive Order S-03-05, which established greenhouse gas emission-reduction targets. We understand that the industry has adopted a 15-year rolling date to determine on-line eligibility. This means systems that went on-line no later than 15 years ago could be eligible for allowance retirement. We want to incentivize the development of new technologies, and we believe that the rolling 15-year on-line date would not provide this incentive. Additionally, as mentioned already in response to other comments received on section 95870, our goal is to move toward greater reliance on auction; this means that the voluntary renewable electricity sector will need to move toward participating in the program in which all of the allowances are auctioned. The voluntary sector will eventually need to register, and purchase and retire allowances, to claim their contributions to reduce greenhouse gas emissions.

VRE Attestations

I-41. Comment: Attestations made by Voluntary Renewable Energy market participants.
In section 95841.1(b)(1)(F)(2), an attestation is required that states the VRE market participant has not "authorized use of, or sold, any renewable electricity credits or any claims to the emissions, or lack of emissions, for electricity for which I am seeking ARB allowance retirement, in any other voluntary or mandatory program." CRS requests clarification that this attestation is to be signed by the VRE market participant on behalf of the end user, and that the end users of the renewable electricity credits are able participate in voluntary renewable energy purchasing programs. It is both commonplace and encouraged for renewable energy purchasers to participate in other programs, including the EPA Green Power Partnership, Green-e Marketplace, the U.S. Green Building Council's LEED certification program, and within GHG registries where REC purchases by the end user can be recorded as zero-emissions electricity use. (CRS3)

Response: Our program will be retiring a certain number of metric tons of allowances for the displacement of an equivalent amount of CO_2e/MWh of generation from an eligible renewable electricity generator. As such, it is our intent the claim to the lack of emissions attribute which allows the participant to retire allowances in our program is not also claimed in another program in which there is an accounting of greenhouse gas emissions reduction. It would not be accurate accounting if the emissions reductions were claimed in our program, and then another program also claimed that the very same MWhs of electricity also reduced emissions in their program. It is not our intention, however, for entities to be prevented from having that claim acknowledged in other recognition programs, such as LEED.

VRE and Double-Counting

I-42. Comment: Sections 95841.1(b)(1)(D) and (b)(1)(E) both require "Contract, tracking system data, or settlement date for the purchase (and sale) of the electricity or RECs associated with the generation of the electricity…" As currently written, this enables double counting as both the REC and the underlying electricity could separately meet the requirements of the VRE set aside using the same MWh. Only the REC, and not the underlying electricity absent a REC, should be allowed to satisfy these requirements, as the REC represents the environmental attributes, including the emissions attribute, of renewable energy generation. CRS recommends striking "electricity or" in each sentence to avoid this potential for double counting. (CRS3)

> **Response:** These comments fall outside of the scope of the second-15 day changes to the regulation. The only change made to the provisions contained in sections 95841.1(b)(1)(D) and (b)(1)(E) was to add the option to use "tracking system data" and require submission of this information. No changes were proposed to the type of data to be reported; therefore it is not subject to public comment under the second-15 day changes to the regulation. Therefore, no further response is required. Nevertheless, we acknowledge the comment provided by CRS. It is not our intention to allow for double-counting. We do not agree with CRS though that the suggested modification would prevent double-counting any more than the provisions already included in this section. CRS suggests that we strike the words "electricity or." If we made this modification, we would eliminate the option to purchase the electricity directly from a generator. We acknowledge CRS's concern, and we will work with stakeholders as we develop specific guidelines for participation in this voluntary program so that we ensure there is no double-counting.

I-43. (multiple comments)
Comment: REMA commends ARB for its improvements on the "First Deliverers" regulatory language outlined in section 95852(b)(3). Program revisions to date have greatly increased the program's integrity of emissions reductions and environmental claims from renewable generation sources. REMA requests that ARB provide clarity within section 95852(b)(3)(D), specifically on reference made to the Mandatory Reporting of Greenhouse Gas Emissions (MRR). The existing language states that "If RECs were created for the electricity generated and reported pursuant to MRR, then the RECs must be retired and verified pursuant to MRR." However, guidance on REC treatment in the referenced MRR section 95111 is unclear. This could be result of placeholder text for future development of the VRE Reserve Account or a general omission. In either case, corresponding MRR language describing the REC retirement process would aid the program's functionality and prevent participant confusion. Additionally, REMA stresses that ARB consider the distinction of REC ownership and REC retirement for purposes of VRE Reserve Account compliance. Currently, section 95852(b)(3)(D) requires the outright retirement of RECs pursuant to guidance in the MRR, a stipulation that decreases the liquidity of the renewable energy markets in California. REC ownership is the critical component in a functioning renewable energy market. Although retirement assists in the validation of environmental claims, REC

ownership satisfies ARB's compliance obligations. Further, outright retirement limits renewable energy trading, overall VRE Reserve Account participation, and possibly the effectiveness of the voluntary program itself. Again, REMA recommends that ARB revise the language in section 95852(b)(3)(D) require ownership of the REC rather than retirement. (REMA3)

Comment: CRS greatly appreciates the addition of section 95852(b)(3)(D) whereby RECs are required in order for electricity importers to claim a zero-emission compliance obligation for delivered electricity from a renewable resource. This requirement will prevent the double counting of renewable energy attributes, help ensure that multiple claims are not made for the same renewable energy generation, and aid in the continued growth of both voluntary and compliance renewable energy markets in the U.S. CRS applauds CARB staff for their careful consideration of this very important issue. It should be noted that while the retirement of the RECs created with electricity imported into California is necessary to prevent double counting, ARB should maintain flexibility to allow trading of the REC within California boundaries, because the final owner and user of a REC may not be the electricity importer. CRS is happy to assist CARB staff with the technical requirements pertaining to this issue. (CRS3)

> **Response:** We do not agree with CRS or REMA and did not incorporate the changes they suggested to allow REC trading beyond the border of California for megawatt-hours that have been reported and applied to the RPS adjustment. Once a REC, which contains the environmental attribute representing the avoided emissions, is used for the RPS adjustment pursuant to section 95852(b)(4), it is required to be retired. If we did not require the retirement of the REC, and it was further traded and used within another voluntary or compliance program, it would be double-counted. The lack of emissions attribute would have already been used under the requirements for receiving the RPS adjustment. If the utility is the entity that will be retiring the REC, then the utility can provide an REC retirement report as documentation to the importer stating the REC was retired for the delivery of electricity, as required pursuant to the MRR.
>
> REMA requests additional clarification of sections contained in the MRR. We acknowledge the comment regarding requirements contained in the MRR. Pursuant to the MRR, electricity importers must be able to provide documentation for verification within 45 days following the June 1 reporting deadline that the RECs have been retired. If the electricity importer's verifier cannot confirm that the RECs are retired, the reporting entity will be in non-conformance. The options for allowable documentation that is acceptable, and that satisfies reporting and verification requirements contained in the MRR, will be included in the guidance document that will be produced as an accompanying document to support the fulfillment of the requirements contained in the MRR.

I-44. (multiple comments)
Comment: In Section 95852(b)(4), language was added whereby firmed and shaped power used to comply with the RPS would receive an adjustment that effectively

eliminated any compliance obligation for first deliverers. If CARB has determined that firmed and shaped power used to meet the RPS should have no compliance obligation, it is consistent to apply this to green pricing programs as well. (CRS3)

Comment: SMUD appreciates the recognition of the need to align the Cap and Trade program with the state's ambitious RPS program. However, we feel it is also important to ensure that resources recognized for RPS compliance are also eligible for green pricing programs that may be offered to customers who would like to purchase renewable energy outside the RPS. While the ARB has included provisions to handle the GHG treatment for purchasing in-state renewable energy for use in voluntary programs, SMUD believes that it is important to ensure harmony where possible with RPS rules that recognize the benefits of out-of-state renewable energy. The following change would allow resources that would normally count for the state's RPS to also be fully viable for voluntary program customer needs without incurring a compliance obligation or challenging the GHG benefits expected from voluntary renewable procurement. Modify section 95852(b)(4) as follows:

(4) Renewable ~~RPS~~ Energy adjustment. Electricity imported or procured by an electricity importer from an eligible renewable energy resource reported pursuant to MRR must meet the following conditions to be included in the calculation of the ~~RPS~~ Renewable Energy adjustment:

(A) The electricity importer must have either:

1. Ownership or contract rights to procure the electricity generated by the eligible renewable energy resource; or

2. Have a contract to import electricity on behalf of a California entity that has ownership or contract rights to the electricity generated by the eligible renewable energy resource, as verified under MRR.

(B) The RECs associated with the electricity claimed for the ~~RPS~~ Renewable Energy adjustment must be deposited prior to verification in a WREGIS account that can only be used:

1. T~~t~~o comply with California RPS requirements ~~during the same year in which the RPS adjustment is claimed~~, or

2. To supply a green pricing program.

(C) The quantity of emissions included in the ~~RPS~~ Renewable Energy adjustment is calculated as the product of the default emission factor for unspecified sources, pursuant to MRR, and the reported electricity generated (MWh) that meets the requirements of this section, 95852(b)(4).

(D) No ~~RPS~~ Renewable Energy adjustment may be claimed for an eligible renewable energy resource when its electricity is directly delivered.

(E) No ~~RPS~~ Renewable Energy adjustment may be claimed for electricity generated by September 2011 an eligible renewable energy resource in a jurisdiction where a GHG emissions trading system has been approved for linkage by the Board pursuant to subarticle 12. (SMUD4)

Response: We do not agree with CRS and SMUD, and did not incorporate the modifications suggested by SMUD to allow for the RPS adjustment to extend to purchases that fulfill utility green-pricing program requirements. We rely upon the requirements set by the California Energy Commission to determine whether a technology or particular generator meets their established eligibility requirements for the Renewable Portfolio Standard. As such, adjustments to a compliance obligation under section 95852 will only be applied for generation that meets these requirements. If electricity under SMUD's green pricing program meets the established RPS requirements, then it will be allowed to take the RPS adjustment. Likewise, if the electricity meets the requirements set forth in section 95841.1 for the voluntary renewable electricity retirement, then SMUD's utility green-pricing program could seek allowance retirement for their green-pricing program.

CRS suggests modifications made to section 95852(b)(4) allow for firmed and shaped electricity used to comply with the RPS adjustment would receive an adjustment, and would thus reduce the compliance obligation. The requirements contained in section 95852(b)(4) address megawatt-hours reported from an eligible renewable facility. All other power needed to firm or shape the renewable purchase will be reported just like any other electricity from a specified or unspecified source. This power will have an obligation for the associated emissions. The adjustment is applied to the compliance obligation of the first deliverer for the megawatt-hours from an eligible renewable facility reported pursuant to the MRR. Therefore, the adjustment is not made directly for, nor tied to, the firmed and shaped power. Again, we do not agree that the adjustment should be extended for renewable electricity generation that does not meet the requirements established by the CEC for RPS eligibility.

VRE Tracking Systems

I-45. Comment: We appreciate the recognition of renewable energy tracking systems in sections 95841.1(b)(2)(D) and (b)(3)(D). Renewable energy tracking systems are the most secure way to guarantee that RECs are properly retired, and help ensure that the correct number of allowances will be retired on behalf of each renewable energy sale.

We seek clarification regarding the required use of renewable energy tracking systems for VRE participants seeking allowance retirement. As currently written, it is unclear if renewable energy tracking systems are or ever will be required for voluntary market participants. While electronic tracking systems are a preferred means for showing REC retirement, they can be cost-prohibitive to generators below a certain size. It is recommended that if renewable energy tracking systems are required, generators below 10 MW be exempt from this requirement. Instead, for smaller generators not in a tracking system, an attestation should be required which states that the market participant has ownership of the renewable energy generation, and that they have not sold the renewable energy attributes separately to other customers or used it to make other renewable energy claims. (KUSTIN17)

> **Response:** We acknowledge the coalition's suggestion to consider attestations required by certification programs for smaller generators less than 10 MW, rather than tracking system data. We are aware that this requirement may place a burden on the smaller generator. However, to accurately account for allowances that will be retired, we will need to verify purchases of electricity and ensure that participants have not separated the REC from the electricity to sell to another entity, or to make a claim in another program. All participants must be able to prove this to ARB. We included a few options to meet this requirement. As we prepare to implement the program, we will prepare guidelines so that participants have a clear understanding of the documentation needed to meet the options included in section 95841.1(b).

General

Jurisdiction, BPA and WAPA

I-46. (multiple comments)
Comment: Bonneville Power Administration (BPA) previously submitted written comments on these matters on December 15, 2010 and August 1, 2011. ARB has not acknowledged or responded to BPA's comments. Western Area Power Administration (WAPA) submitted similar comments, which ARB has also failed to address. BPA will not repeat its earlier comments, but hereby incorporates them by reference. BPA again requests that ARB act on its comments, as set forth in its August 1, 2011 filing. As BPA has previously discussed with ARB staff, it is BPA's intent to voluntarily report on GHG emissions. BPA strongly disagrees with ARB's suggestions in its greenhouse gas reporting rules and cap and trade rules that it has "authority" to regulate BPA and that BPA is "required" to comply. BPA wishes to make clear that BPA is participating in California's GHG reporting program and cap and trade program purely on a voluntary basis, and BPA is not conceding that California has any jurisdiction over BPA. BPA files this letter to preserve that position. (BONNEVILLEPWR3)

Comment: Western Area Power Administration (Western) previously submitted written comments in the above proposed rules. Western will not repeat its earlier comments, but hereby incorporates them by reference. Western continues to express concerns that California Air Resource Board (CARB) is requiring federal agencies to consent to state jurisdiction. For instance, Section 96022 provides: Any party that participates in the Cap-and-Trade Program is subject to the jurisdiction of the State of California. These types of provisions could significantly impact the ability of federal agencies to voluntarily comply with CARB's proposed rules. Federal agencies are unable to consent to state jurisdiction without an express waiver of sovereign immunity. Only the U.S. Congress (with consent by the President) can waive sovereign immunity.

Western continues to encourage CARB to modify these provisions and acknowledge that federal agencies are not subject to state jurisdiction. While Western continues to disagree with CARB's suggestions in its greenhouse gas reporting rules and cap and trade rules that CARB has "authority" to regulate Western and that Western is "required" to comply, Western supports the state initiatives and has attempted to voluntarily participate in the state's green house gas (GHG) programs. Western understands the importance of having all in-state utilities participate in the GHG programs and to this end Western has had numerous conversations with and has provided data to CARB staff.

While Western welcomes continued interaction with CARB, Western wishes to make clear that Western's participation in CARB's GHG reporting program and cap and trade programs are on a voluntary basis and Western is not conceding that CARB has jurisdiction over Western in these matters. After CARB issues its final rule, Western will evaluate if, how, and to what extent, Western can voluntarily participate in CARB's GHG programs. (WAPA3)

> **Response:** ARB believes that section 118 of the Clean Air Act waives sovereign immunity for BPA. Additionally, this document only responds to comments regarding the cap-and-trade regulation (which includes section 95802) but does not include the other specific sections with which BPA takes issue, which are included in the MRR . Although the definition of "electricity importer" has changed through the course of two 15-day notices, BPA, DWR, and WAPA remain specifically named as electricity importers to California and subject to the cap-and-trade regulation.
>
> Section 118 of the Clean Air Act (42 U.S.C. 7418 (a)) provides a waiver of sovereign immunity for regulations to control air pollution:
>
> > "Each department, agency, and instrumentality of the executive, legislative, and judicial branches of the Federal Government … engaged in any activity resulting, or which may result, in the discharge of air pollutants… shall be subject to, and comply with, all Federal, State, interstate, and local requirements, administrative authority, and process and sanctions respecting the control and abatement of air pollution in the same manner, and to the same extent as any nongovernmental entity. The preceding sentence shall apply … (B) to any requirement to pay a fee or charge imposed by any State or local agency to defray the costs of its air pollution regulatory program… This subsection shall apply notwithstanding any immunity of such agencies, officers, agents, or employees under any law or rule of law."
>
> The United States Supreme Court, in *Massachusetts v. EPA,* 549 U.S. 497 (2007) determined that greenhouse gases are "air pollutants" as that term is defined in the Clean Air Act. The regulation constitutes an air pollution regulatory program designed to control greenhouse gas, and therefore falls within the

waiver of sovereign immunity provided by section 118 of the Clean Air Act. ARB appreciates BPA's participation in the programs operated by ARB.

Recommend New Regulatory Proceeding

I-47. Comment: LADWP strongly supports ARB's action to initiate a new regulatory proceeding in 2012 to address outstanding issues, including resource shuffling and electricity imports. LADWP recognizes that ARB plans to finalize this regulation by the October 28, 2011 deadline for submittal to the Office of Administrative Law. It is LADWP's understanding that ARB will initiate a separate regulatory proceeding in 2012 to address outstanding issues related to the implementation of the Cap-and-Trade program. LADWP recommends that this new proceeding be initiated as soon as possible and be flexible for staff to address unresolved issues that have already been identified, such as resource shuffling, as well as any new issues in relation to the Second 15-Day Modified Text, including those related to electricity imports.

As mentioned by many parties in response to the First 15-Day Modified Text, the inclusion of the new resource shuffling provisions requires a significantly more thorough review process to allow ARB staff and stakeholders an opportunity to better understand the intent of the language and to properly vet the potential implications for the electricity sector. This proceeding should include marketers, utilities, other market participants, CPUC, CEC, and CAISO as well as the WECC, NERC and FERC to ensure that this regulation, as it applies to electricity imports to California, accurately and consistently assigns emissions liability, promotes reliability, supports efficient market transactions, appropriately accommodates load emergencies in the WECC, and stands strong against potential legal infirmities. (LADWP5)

Response: ARB will continue to work with other State and federal agencies to monitor the impacts of the regulation all sectors, including the electricity sector. ARB will evaluate all areas of implementation, and will propose additional changes if needed. However, ARB has not specifically committed to opening a new rulemaking in 2012 for the purpose noted by the commenter, nor for any other purpose.

I-48. Comment: The resource shuffling provision does not accommodate load emergencies where a first deliverer may be asked to supply excess power under mutual assistance. The priority for grid operators is, first and foremost, coordinating and promoting bulk electric system reliability to avoid costly regional power outages that risk life and property. LADWP previously expressed concerns that the inclusion of the resource shuffling provision does not necessarily coincide with the normal and emergency operations of the grid required by Federal Energy Regulatory Commission (FERC) reliability standards. The inter-connectedness of the electrical transmission grid was recently demonstrated during a regional 12-hour blackout earlier this month that was triggered in Arizona and that affected areas as far away as San Diego, parts of Orange County and Riverside County and cost an estimated $97-$118 million in losses.

Given the critical nature of blackouts, LADWP strongly recommends that the ARB Board provide direction in the Board resolution to establish procedures under emergency scenarios that allow a covered entity to provide mutual assistance without the risk of penalty enforcement for perceived resource shuffling. A covered entity should not be forced to choose between providing mutual assistance to another load serving entity or staying in compliance with resource shuffling provisions of an emissions Cap-and-Trade program. As currently written, the regulation does not include a mechanism for distinguishing a real load emergency from any other type of market transaction that ARB might legitimately consider resource shuffling, the regulation does not include a mechanism for distinguishing a real load emergency from any other type of market transaction that ARB might legitimately consider resource shuffling. (LADWP5)

> **Response:** It is not our intent to capture typical electricity market activity under resource shuffling. This includes LADWP acting under an emergency situation to import power, or when providing mutual assistance under an emergency situation. The definition of "resource shuffling" and the prohibition are designed to capture intentional changes in market activity to avoid a compliance obligation. Legal requirements pursuant to the final regulation are clear. Consistent with ARB practices in implementing the regulation, we will continue to work with covered entities to ensure a successful program implementation. ARB continually evaluates its programs and will determine when future amendments are appropriate.
>
> In Resolution 11-32, the Board directed the Executive Officer to continue discussions with stakeholders to identify and propose, as necessary, during the initial implementation of the cap-and-trade program, potential amendments to the regulation, including the definition of "resource shuffling," to: (a) provide appropriate incentives for accelerated divestiture of high-emitting resources by recognizing that these divestitures can further the goals of AB 32; and (b) ensure that changes in reported emissions from imported electricity that serves California do not result merely in a shift of emissions within the Western Electricity Coordinating Council region, but instead reduce overall emissions.

Recommended Board Resolution

I-49. (multiple comments)
Comment: NextEra supports the comments submitted by two of our trade groups; the Independent Energy Producers of California (IEP) and the Western Power Trading Forum (WPTF). Highlighted below are several issues we feel must be addressed by ARB staff. Please refer to the comments submitted by IEP and WPTF on these issues. The specific areas NextEra has identified as areas of concern include:

- Criteria for utilizing the "RPS Adjustment" for imported renewable energy are not consistent with the California Public Utility Commission (CPUC) RPS program.
- The Resource Shuffling definition is still very broad and may impede market efficiency.

- Despite the direction of the Board Decision December 16, 2010, ARB staff has not provided a tangible cost-recovery option for independent energy producers subject to pre-existing power purchase contracts.
- The definition of Electricity Importer is still unclear and needs to be further developed in conjunction with CAISO, CPUC, and CEC staff.

It is important for ARB staff to address these issues adequately prior to the program going live in 2013. If these issues are not addressed by the Oct 28, 2011 deadline for submission to the Office of Administrative Law, NextEra urges ARB to open new rulemaking either late 2011 or early 2012 to address these specific issues in the regulation. This will allow time to gather input from all interested parties as well as experts in the electricity markets. It is important that the regulations are effective in reducing GHG emissions at the least cost to consumers. It is also important that the regulation of GHGs does not add unnecessary complexity to the electricity markets and all parties are treated fairly. The timing of the potential new rulemaking is critical and NextEra suggests that every effort be made to complete this process prior to the program launch in January 2013. (NEXTERAENERGY3)

Comment: WPTF remains concerned with several provisions in the Regulation that have the potential to unnecessarily raise costs impair the ability of obligated entities to comply with the cap and trade program. Several provisions could impair the ability of obligated entities to comply with the cap and trade program and the state's Renewable Portfolio Standard (RPS):

- Despite the guidance provided in the December Board Resolution approving the cap and trade program, the modified regulation does not adequately address the issues associated with carbon cost recovery by independent power producers operating under long-term contracts that pre-date AB 32 and do not provide for pass through of those costs.
- The definition of resource-shuffling is overly broad and could inhibit legitimate imports of clean energy.
- Requirements for claims of specified renewable imports and the RPS Adjustment conflict with the multi-year compliance framework of the RPS law.
- The approach to netting of "qualified exports" against an entity's imports within the same hour will significantly overstate California electricity consumption, thereby arbitrarily and unnecessarily raising allowance prices and overall electricity prices, and making the cap and trade regulation more vulnerable to legal challenges from electricity importers.

Due to the truncated rule-making process this year, WPTF believes that these issues have not been adequately considered and addressed by CARB. In our more detailed comments below, we explain why the Board must take action to ensure that CARB staff may continue to make modifications to address these important issues. WPTF understands the Board's desire to adopt an modified regulation so that implementation of the cap and trade program can proceed in 2012, and the concern that an acknowledgement that further refinements to the modified regulation are necessary may stand in the way of such implementation. WPTF does not believe that action by the

Board to preserve the ability for Staff to continue vetting these important issues with market participants, and to bring modifications to the Board as necessary, will serve in any way to conflict with adoption of the modified regulation in October. In fact, WPTF would support adoption of the cap and trade program in October, provided that CARB work to improve the modified regulation through stakeholder workshops and rule-making in 2012. We therefore urge that the following language be include in the Board Resolution adopting the cap and trade program:

“The Board directs the Executive Officer of the Air Resource Board to initiate Rulemaking to be completed by June 2012 to address the following outstanding issues in the cap and the trade program:

1) Establishment of a process to identify and provide for carbon-cost recovery to independent power producers operating under long-term contracts that do not provide for pass through of costs associated with compliance with the cap and trade program on a case by case basis;

2) Review of the auction purchase and holding limits to ensure that they are equitable to all covered entities and do not impair the ability of entities to manage costs of compliance with the program;

3) Review and modify the requirements for electricity imports, including:

   a. Elaboration of the definition of “resource-shuffling‟ and requirements for specified imports to ensure consistency with AB 32 goals, to provide clarity to importers and verifiers on how to identify (and thus avoid) resource-shuffling, and to permit legitimate claims to specified imports;

   b. Evaluation, and modification, of the requirements for renewable imports and the RPS Adjustment to ensure they are consistent with the statutory RPS framework and implementing regulations developed by the California Public Utilities Commission (“CPUC”) and California Energy Commission (“CEC”).

   c. Revision of the requirements for “qualified exports” and associated emissions subject to the cap and trade program to ensure that compliance emissions for the electricity sector accurately reflect California consumption of electricity;

The Board further directs the Executive Officer to contract with an independent entity with appropriate expertise in wholesale electricity markets to assist staff in addressing the complexities associated with implementing these regulations for electricity imports." (WPTF3)

Response: Legal requirements pursuant to the final regulation are clear. Consistent with ARB practices in implementing the regulation, we will continue to work with covered entities to ensure a successful program implementation. ARB continually evaluates its programs and will determine when future amendments are appropriate. Board Resolution 11-32 directs the Executive Officer to report on the status of the cap-and-trade program at least annually. Board Resolution 11-32 also directs the Executive Officer to continue discussions with stakeholders to identify and propose, as necessary, during the initial implementation of the cap-and-trade program, potential amendments to the regulation, including the definition of “resource shuffling,” to: (a) provide appropriate incentives for accelerated divestiture of high-emitting resources by recognizing that these divestitures can further the goals of AB 32; and (b) ensure that changes in reported emissions from imported electricity that serves California do not result merely in a shift of emissions within the Western Electricity Coordinating Council region, but instead reduce overall emissions.

Long-Term Contracts

I-50. (multiple comments)
Comment: In keeping with CARB staffs preference for long-term contract generators (LTCG) that cannot pass through new environmental costs to work directly with their customers, Panoche has continued to try to resolve this issue with PG&E. Unfortunately, PG&E has refused to work with us to find an equitable solution. Understanding that such negotiations were likely going to prove extremely difficult, Panoche, in its August 11, 2011 comments, urged that "to encourage negotiations between affected LTCGs and utilities, the Board should also consider providing that the parties engage in good-faith bilateral negotiations to resolve the issue of cost of compliance during 2012, before compliance obligations commence on January 1, 2013. If the parties have not come to a mutually-agreeable resolution at that time, the regulation should provide that LTCGs are granted allowances under the outlined terms." Although CARB staff continues to acknowledge this issue and its need for resolution, we were disappointed to find that staff, in its Second Notice of Public Availability of Modified Text issued on September 12, 2011 neither addressed nor resolved this issue.

Having taken staffs advice to attempt to resolve this issue in a bilateral fashion and having exhausted all avenues to try to resolve this issue with PG&E, we again urge CARB to directly address this issue through regulation. As such, we agree with the Independent Energy Producers Association's and Wellhead Electric's proposal for resolving this issue through an amendment of section 95834 "Disclosure of Beneficial Holding Relationships." This equitable solution would require an electric distribution facility to hold and surrender allowances for an LTCG's GHG compliance requirements as long as the LTCG is under a pre-AB 32 long-term contract with the electric distribution utility. Such an arrangement would be consistent with CARB's concept and regulatory construct of "beneficial holding relationships." Without relief provided by regulations, the new costs associated with AB 32 compliance will have a substantial negative impact on the financial viability of our facility as well as a limited number of other LTCGs. (PEC2)

Comment: In its present form the Cap and Trade Regulation is fundamentally unfair to holders of power purchase and sales agreements with electric utilities that were entered into before AB 32 was enacted ("Long-Term Contracts"). Because the Long-Term Contracts do not specifically provide for pass-through of GHG costs, the language of the Cap and Trade Regulation exposes the generators holding the Long-Term Contracts to substantial financial injury if the utilities refuse to assign GHG emission credits or allowances to them. Any hope of utility cooperation that could cure the above-mentioned shortcoming suffered a significant blow within days of the close of the comment period on the Cap and Trade Regulation. It is our understanding that some Fossil generator holders of the Long-Term Contracts (specifically tolling agreements) that have recently inquired have been bluntly notified by their utility counterparties that there will be no consideration whatsoever given to pass-through of GHG costs. It is therefore already quite clear that, absent corrective action by CARB, the imbalance of the economic interests of the parties to the Long-Term Contracts under the current Cap and Trade Regulation will have the predicted consequence of causing an increase in GHG emissions.

Additionally, Midway supports the Independent Energy Producers Association recent filing made to the CPUC concerning this threat and although this may seem to be this may be a small issue in the larger scheme of AB 32 implementation, for those of us impacted by this situation it is very serious. The uncertainty of what the impact of GHG compliance will be is causing apprehension as to the planning for operations and maintenance of these existing facilities. If we remain unable to recover the costs of GHG compliance, are not allocated any allowances and have to perform under our existing long term contracts, it is possible that we could eventually default on loan covenants and in the end cease to operate. We ask that the CARB staff assists in getting a solution in place for the small group of projects affected by this issue. The situation will not just go away.

Starwood Power-Midway, LLC urges that CARB seek to amend Section 95834 of the Cap and Trade Regulation to require utilities to enter into a "beneficial holding relationship" to cover the GHG emissions obligation of generators providing power and energy to the utilities under the Long-Term Contracts. A beneficial holding relationship should be deemed to exist pursuant to Section 95834(a)(1)(A) for any Long-Term Contracts that have not been clarified or renegotiated as of January I , 2012 to address GHG costs. Utility parties to the Long-Term Contracts should be required to purchase and hold allowances for the eventual transfer to generator parties for the sole purpose of supplying generators with credits or allowances sufficient to cover GHG emissions obligation under the Long-Term Contracts. An alternative approach would be to waive compliance on a case-by case-basis for as long as utilities withhold allowances or credits from generator owners that hold Long Term Contracts that can demonstrate financial hardship and good faith efforts to comply with the Cap and Trade Regulation.

In the absence of direct allocation of allowances to generator-holders of Long-Term Contracts, CARB should either amend the Cap and Trade Regulation as described here or grant limited waivers of section 95834 under defined circumstances as it relates to specific Long-Term Contracts. Thank you for your prompt attention to this notification of a predicted problem become real, and proposed solutions to correct a serious flaw in the Cap and Trade Regulation. We again urge CARB to directly address this issue through regulation. The equitable solution would require an electric distribution facility to hold and surrender allowances for an LTCG's GHG compliance requirements as long as the LTCG is under a pre-AB 32 long-term contract with the electric distribution facility. Such an arrangement would be consistent with CARB's concept and regulatory construct of "beneficial holding relationships." Without relief provided by regulations, the new costs associated with AB 32 compliance will have a substantial negative impact on the financial viability of our facility as well as a limited number of other LTCGs. (SPM)

Comment: Wildflower is very concerned that the regulation does not address, much less resolve, the circumstances of generators locked into long-term contracts executed before AB 32 was signed into law. Because these long-term contracts were entered into prior to AB 32, these contracts do not provide for recovery or allow for a pass through of greenhouse gas (GHG) compliance costs. As discussed below, CARB must take steps to specifically address these contracts in order to fulfill CARB's emission reduction objectives in an equitable manner. One of the fundamental assumptions of the cap-and-trade regulation is that generators and marketers will pass their GHG compliance costs onto the utilities. This assumption is not applicable to this special situation of pre-AB 32 long-term contracts.

Wildflower is the owner of Larkspur Energy and Indigo Generation, two natural gas-fired power plants operating in Southern California (facilities). On January 17, 2001, Governor Gray Davis proclaimed a State of Emergency to exist due to the energy shortage in the State of California. Subsequently, on February 8, 2001 and on March 7, 2001, Governor Davis issued Executive Orders D-26-01 and D-28-01, requiring the Energy Commission to invoke the emergency siting procedures in Public Resources Code section 25705 to expedite the licensing of all new renewable and peaking power plants that could be available for service no later than September 30, 2001. In these orders, Governor Davis declared that all reasonable conservation, allocation, and service restriction measures will not alleviate this energy supply emergency and that new generation was needed to avert an immediate threat to public health and safety. Larkspur was the first facility licensed under this emergency siting process and Indigo was similarly licensed under this process. At that time, the State strongly encouraged execution of long-term power purchase agreements for these emergency facilities, in order to avoid some of the spot-market fluctuations that exacerbated the energy crisis. Wildflower's facilities entered into long-term tolling contract with a third-party power marketer through 2021 which does not provide any mechanism for cost recovery of GHG gas compliance costs. The marketer that purchases power under this contract has declined to renegotiate to address these substantial and previously unforeseen GHG costs. Consequently, Wildflower has no ability to recoup the GHG compliance costs starting July 2012, when the first cap-and-trade auction occurs.

Failure to timely address pre-AB 32 long-term contracts undermines the equity and integrity of CARB's cap-and-trade program. One of the assumptions underlying the cap-and-trade is that generators and marketers will pass their compliance costs onto the utilities. Appendix A of the regulation notes that "a central principle of the allowance allocation to the electricity sector is the incorporation of customer cost burden. Cost burden is expected to result from emissions costs associated with fossil, QF, and non-emitting resources priced at market being passed from generators and marketers to utility customers." However, in the case of Wildflower selling to a marketer, the utility will purchase power at a market price that includes a GHG cost assumption, but the marketer will never actually incur the costs of GHG compliance because Wildflower's facilities could not pass on their GHG compliance costs. This potentially gives arise to a (much abhorred) windfall profit opportunity for the marketer.

Further, the fundamental emission reduction goals of the cap-and-trade will be thwarted if CARB does not address these pre-AB 32 long-term contracts. Some of these contracts, including Wildflower's agreements, are structures where the purchasing entity can effectively call on the generator to run (full dispatch control). These contracts will be the only resources where the purchaser does not face a GHG compliance cost. Consequently, the purchaser will have an incentive to run the resource more often, irrespective of its GHG emissions profile. This result has the potential for disrupting the most efficient use of California's resources, and will tend to increase overall GHG emissions levels.

The need to address pre-AB 32 long-term contracts is clear, and yet there is no recognition of the issue in the September 2011 version of the regulation. Moreover, the counter-parties to these contracts currently have no incentive to renegotiate the terms of these agreements. Wildflower requests that CARB specifically acknowledge the need to timely address the pre-AB 32 long-term contract issue in the resolutions for adoption of the cap-and-trade regulation. A draft Board Resolution is attached to this letter as Attachment 1. Additionally, Wildflower requests that CARB direct staff to continue to evaluate and work with affected generators towards the successful resolution of these concerns.

Wildflower provides three proposals with suggested amendments to the regulation to address the pre-AB 32 long-term contract issue in Attachment 2. Wildflower welcomes the opportunity to provide additional input to staff on specific ways in which these issues may be resolved.

Wildflower Proposed Board Resolution Addressing pre-AB 32 Long Term Contracts:

WHEREAS some electricity generators and combined heat and power facilities entered into long-term contracts before the enactment of AB 32, which do not provide any mechanism for pass-through of costs associated with greenhouse gas emissions.

WHEREAS without further consideration from CARB of pre-AB 32 long-term contracts that do not allow for pass-through of costs associated with greenhouse gas emissions, parties that do not bare greenhouse costs compliance costs under these contracts will not have an incentive to renegotiate the contracts to provide pass-through of greenhouse gas costs.

NOW THEREFORE staff will work with interested stakeholders to ensure proper treatment under the regulation of any electricity generators or combined heat and power facilities with pre-AB 32 long-term contracts that do not allow for pass-through of costs associated with greenhouse gas emissions.

Wildflower's Proposals for Cap-and-trade Regulation Amendments to Address Pre-AB-32 Long-term Contracts with no Available Mechanism for Pass-Through of GHG Costs:

Proposal 1: Require the creation of a beneficial holding relationship when parties to a pre-AB 32 long term contract without GHG cost recovery do not renegotiate the agreement. Add Subsection 95834(d):

(d) In the event there is a Long-Term Contract for the sale of electricity at wholesale which: i) does not directly or indirectly provide or refer to GHG costs either explicitly or through a) a CPUC approved contract or, b) a CPUC authorized pricing basis that includes GHG costs, ii) was fully executed before the final approval of AB 32 (September 27, 2006); and, iii) has not been renegotiated as of January 1, 2012 to address GHG costs, then, a beneficial holding relationship is deemed to exist pursuant to section 95834(a) without further action. The purchasing party to the Long-Term Contract shall purchase and hold allowances for the eventual transfer to the other party to the Long-Term Contract for the sole purpose of supplying the second entity with compliance instruments to cover emissions resulting from satisfaction of the Long-Term Contract.

Proposal 2: Provide a narrowly tailored exemption for generators that are operating under a pre-AB 32 long term contract without GHG cost recovery. Add Sub-Section 95852.2(d):

(d) The operators of existing combined heat and power and generation facilities that operate under a contractual arrangement executed before September 27, 2006, does not provide or refer to either explicitly or through a) a CPUC approved contractor. b) a CPUC authorized pricing basis that includes GHG costs, ii) was fully executed before the final approval of AB 32 (September 27, 2006): and iii) has not been renegotiated as of January 1, 2012 to address GHG costs.

Proposal 3: Provide free allocation of allowances. Add Sub-Section 95870(/):

(f) Allocation for the purpose of assistance to generators and combined heat power facilities with no means of GHG cost recovery. The Executive Director shall transfer allowances necessary to cover the operation of the generators or combined heat and power facilities that meet the following qualifications: the operators of existing combined heat and power and generation facilities that operate under a contractual arrangement executed before September 27, 2006, does not provide or refer to either explicitly or through a) a CPUC approved contract or , b) a CPUC authorized pricing basis that includes GHG costs: ii) was fully executed before the final approval o(AB 32 (September 27. 2006): and, iii) has not been renegotiated as of January I, 2012 to address GHG costs. (WILDFLOWER)

Comment: Wellhead Electric Company, Inc. (Wellhead) is disappointed and remains very concerned that the proposed cap-and-trade regulations still do not address the problems associated with contracts that were executed prior to AB 32 which do not have any mechanism available for recovery of GHG costs. As more fully discussed in our comments on the prior version of these regulations, unfairness, counter-to-AB 32 behaviors, and unintended enrichment (windfall profits) will result if the problem is not fixed. The solution is very simple but without action by the California Air Resources Board, it is highly unlikely the issue will do anything other than continue to be a problem. Wellhead does understand from workshops discussions and communications with staff that the problem is recognized and that the California Air Resources Board will address and fairly resolve the problems before the regulations take effect. Our prior comments are attached hereto for your convenience. We look forward to working with the CARB staff to address/resolve this significant problem which the current versions of the regulations ignore. (WEC3)

Comment: ARB should reiterate their policy to consider, on a case-by-case basis, the need for adjustment to allowance allocations for firms operating under long-term contracts. (IGPACC2)

Comment: PEB incorporates by reference and reiterates its previous comments to the first 15-day Amendments that were submitted by PEB and received by CARB on August 11, 2011. PEB strongly believes that those comments reflect the unique posture of PEB as a stranded cogeneration facility and merit immediate consideration. PEB looks forward to the CARB's attention to those concerns as the project anticipates that the current regulations pose a potentially adverse impact upon PEB's long-term financial viability and, in turn, UC-B's access to reliable thermal energy.

PEB notes that in the 2nd 15 day Amendment to the California Cap on Greenhouse Emissions and Market-based Compliance Mechanisms, CARB has selectively encompassed all facilities under NAISC code 92811 and has given them an additional year of compliance exemption (see section95852.2(c)). While this additional exemption is narrow in its current focus, it is our hope that it could provide CARB with a basis to offer a similar exemption to PEB through the expiration of PEB's energy supply agreement with UC-B in 2017, at which point PEB will be free to negotiate a cost recovery mechanism with its thermal customer. A CHP facility such as PEB represents a class of generation assets that merit "appropriate incentives" as outlined in California Cap and Trade Program Resolution 10-42, yet PEB is clearly stranded under the currently proposed modified Cap-and-Trade regulations and lacks a cost recovery or pass-through mechanism tied to the end user of the thermal energy that it generates, as contemplated by AB 32 and by the clear intent of the public policy that underlies this program. A decision by CARB to decline to address this difficult issue facing PEB would only further the inequitable result embodied in the current regulations, which acknowledge certain gaps in the regulations with respect to select affected parties, yet fail to address the real needs of a similarly situated facility. PEB is proud of its record as a responsible environmental steward and looks forward to working with CARB to refine the proposed cap and trade regulations to underscore California's need for efficient cogeneration technology as a critical part of any long term solution to the challenge of limiting man made greenhouse gas emissions. (PEBI2)

Comment: Allowances should be granted to entities with no ability to pass through costs; changes creating new disadvantaged parties should be rejected. In the December Board Resolution approving the cap and trade program, the Modified Regulation Order does not adequately address the issues associated with carbon cost recovery by entities obligated under long-term contracts. As noted in comments and in CARB stakeholder processes, renegotiation is not possible in situations where one party is disadvantaged. There is no incentive for the advantaged party to negotiate. CARB should provide free allowances to those limited number of entities that entered long-term contracts that have no ability to pass through the cost of carbon. (SHELLENERGY2)

Comment: The modified regulation must include a mechanism to adequately address the issues associated with carbon-cost recovery to independent generators operating under long-term contracts that do not provide for pass through of the compliance costs. The CARB Staff proposal for modification to the original proposed regulatory order, submitted to and approved by the Air Resources Board on December 16, stated that "Staff will work with interested stakeholders to ensure proper treatment under the regulation of any electricity generators or combined heat and power facilities with pre-AB 32 long-term contracts that do not allow for pass-through of costs associated with greenhouse gas emissions." WPTF members, as well as other affected power producers have had numerous interactions with CARB staff on this issue over the past year. WPTF understands CARB's desire that such issues should be address by the contractual counterparties, and it is WPTF understanding that attempts to do so remain ongoing. Nevertheless, the fact remains that there is little incentive for a contractual solution when the parties to the transaction are not approaching the negotiations on a level playing field; the current modified regulation disadvantages one counterparty over the other, ultimately discouraging contract renegotiation. WPTF has provided CARB staff with proposed language to address these issues. Despite these efforts, the modified regulation still provides no mechanism to ensure that affected power producers can recover their carbon cost, even though other capped entities that cannot recover carbon costs receive direct assistance in the form of direct allowance allocation. WPTF has previously provided recommendations on criteria for evaluating the situation of power producers under long-term contracts and a process for ensuring cost recovery through allowance allocation. We urge CARB to establish a process to:

- Define the conditions under which an independent power producer would be eligible for cost-recovery assistance (e.g., contracts entered into after adoption of AB 32 would not be eligible for relief);
- Identify documentation to be provided by the producer to demonstrate that it meets these conditions;

- Facilitate renegotiation of contracts in cases where the counter-party receives a direct allocation of allowances under the cap and trade program; and/or
- Provide for direct allocation of allowances to independent power producers to cover emissions associated with these contracts in cases where the contract cannot be renegotiated. (WPTF3)

Comment: Calpine is disappointed that CARB has again failed to address the situation faced by long-term contract generators that cannot recover the cost of allowances from their customers under contracts initially entered into prior to the passage of AB 32.

As we previously noted, the problem is particularly acute for generators selling electricity and/or useful thermal energy to nearby or collocated industrial operations under long-term contracts. These combined heat and power (CHP) or cogeneration facilities represent a highly efficient, environmentally preferable alternative to meeting industry's energy needs. For this reason, CARB has made expansion of CHP a significant component of its overall Scoping Plan, which targets an increase of 4,000 MW of installed CHP capacity within the State by 2020. In light of this mandate, "the Board direct[ed] the Executive Officer [in Resolution 10-42] to review the treatment of combined heat and power facilities in the cap-and-trade program to ensure that appropriate incentives are being provided for increased use of efficient combined heat and power."

As we previously noted, however, in many cases industrial facilities qualifying for free allowances under the Proposed Regulation purchase power and steam from a cogeneration facility pursuant to a contract that does not provide any means for recovery of the cogeneration facility's allowance costs. As a consequence, the industrial host will experience no increase in its energy costs due to a fixed price in a contract that pre-dates AB 32 with a CHP generator, even though it will receive a direct allocation from CARB to address potential leakage concerns. Given the anticipated increase in operating costs associated with purchase of allowance, the CHP facility would, in many cases, have little incentive to continue operating and could very realistically decide to just shut-down. Such a result would not only undermine the Scoping Plan goal of increasing CHP throughout the State by 4,000 MW of CHP capacity, it could result in a net reduction of that amount.

Given this possible outcome and the Scoping Plan's goal, CARB staff committed prior to approval of the Proposed Regulation in December 2010 to "work with interested stakeholders to ensure proper treatment under the regulation of any electricity generators or combined heat and power facilities with pre-AB 32 long-term contracts that do not allow for pass-through of costs associated with greenhouse gas emissions." However, in both the First 15-Day Amendments and the Second 15-Day Amendments, CARB Staff has failed to propose any regulatory provisions that would alleviate the extreme economic burden imposed upon long-term contract generators that cannot recover allowance costs from their customers. Instead, Staff noted the concern in the Notice accompanying proposal of the First 15-Day Amendments and suggested that this problem should be resolved through bilateral contract negotiations.

We understand that CARB Staff may have been reluctant to propose regulatory language that could frustrate ongoing efforts between long-term contract generators and their counterparties to resolve this issue, independent of any resolution within the final regulation. However, by failing to include any mechanism to address this problem in either set of 15-Day Amendments, CARB Staff has not only failed to carry out the Board's instructions to address this issue, but may have frustrated any realistic chance that this problem will be successfully resolved by long-term contract generators and their counter-parties.

As detailed the Initial Statement of Reasons for the cap-and-trade regulation, some generators and industrial steam producers have reported that some existing contracts do not include provisions that would allow full pass-through of carbon costs associated with cap-and-trade. Staff is evaluating this issue to determine whether some specific contracts may require special treatment on a case-by-case basis. In several cases, staff is aware and encouraged that parties are in the process of, or already have negotiated new contracts to resolve this issue. Staff believes that bilateral contract negotiations would provide the best resolution of this issue. Should contract renegotiation not be possible in all cases, staff will continue discussions with counterparties to consider how this issue should be resolved in the regulation. Should the final regulation not address this issue and instead award free allocations to industrial entities purchasing steam or power pursuant to long-term contracts that do not provide for recovery of allowance costs, those entities will have little to no incentive to assume some share of responsibility for the generator's allowance costs.

Calpine is endeavoring to work with its counter-parties to address this situation via bilateral contract negotiations. However, we are not hopeful that we will be able to resolve the situation in all cases, particularly given CARB's failure to address the issue in either package of 15-Day Amendments. We continue to believe that the best way to address this problem is through a direct allocation of emissions allowances to generators subject to long-term contracts that provide no mechanism for recovery of allowance costs. This would merely provide transitional assistance until such time as the existing contract expires or is substantively amended, as reflected by the specific language we proposed in our December 2010 Comments. As we previously proposed, none of the allowances provided for such assistance could be sold or otherwise used by the generator to experience some windfall in profits.

At the very least, we believe CARB must revise the Proposed Regulation so that, where entities that would receive an allocation for industrial assistance will experience no increase in their energy costs due to a pre-AB 32 contract, the allowances will not be awarded to that entity, but will be given to its counter-party instead. If CARB cannot incorporate provisions addressing long-term contract generators into the final regulation, we strongly urge the Board to instruct Staff to address this issue in a separate rulemaking to be commenced at the earliest opportunity in 2012. (CALPINE4)

Comment: We are disappointed that CARB refuses to address the need for a mechanism to allow compliance cost recovery for small generators such as WM's Norwalk combined heat and power (CHP) facility. Failure to provide for equitable resolution of contract provisions will result in small generators shouldering the burden of compliance costs to meet the requirements of cap and trade. The regulation incorrectly assumes contract renegotiation will resolve this cost issue, thus assuming both parties are equal in their contract position. Nothing could be further from the truth. We understand that CARB has deferred the effectiveness of covered entities' compliance obligation under cap and trade regulations until January 1, 2013, perhaps believing there is time to resolve this important issue in future rulemaking. However, time is of the essence. The auctions of GHG emission allowances will begin in the second half of 2012. Thus, by no later than the second quarter of 2012, the Norwalk facility must decide whether and to what extent we must obtain GHG emissions allowances in the auctions. Our compliance decisions must be made based on a clear understanding of whether and how we are able to comply with the CARB regulations. Merely "punting" this issue to the California Public Utilities Commission (CPUC) in hopes that agency will address cost recovery for certain independent power producers like Norwalk will not resolve the issue, as there is no legal proceeding available at this time that has accepted the issue for proper hearing and resolution to make right the current inequity. We urge CARB to reconsider its position to remain silent in the current rulemaking, or move in an expedited fashion as part of another rulemaking to address this issue. (WM4)

Comment: SMUD invested in three cogeneration facilities in the 1990's to provide clean, efficient power for our ratepayers while encouraging low-emissions industrial facilities in our service area. Unlike typical cogeneration facilities, which supply electricity and steam to an industrial facility and sell any excess electricity to the grid, these cogeneration plants provide electricity only to the grid and supply steam which is sold over-the-fence to industrial facilities nearby. The contracts for steam sales to these industrial facilities allow no flexibility for pass through of the carbon allowance costs. Nor were the emissions from providing this steam recognized in the ARB methodology for allocating allowances to electrical distribution utilities, as this was based upon retail load projections alone, ignoring steam sales. Hence, SMUD and SMUD's ratepayers have the obligation of compliance for the emissions associated with the steam sales, but the Cap and Trade program does not recognize this obligation. The proposed 15-day language for the Cap and Trade program imposes an allowance obligation on the extra emissions needed to produce process steam that is delivered to industrial customers near the plant, but not used to cover SMUD's retail load.

A remedy for this apparently uncommon cogeneration arrangement would be to allocate to the steam provider a requisite portion of allowances from the industrial sector to cover emissions associated with provision of steam to the industrial customers. This would partially remove the burden to SMUD ratepayers and the otherwise illogical problem of a combined cycle generation facility with what appears to be a higher heat rate than normal. To acknowledge this situation and accommodate others that may potentially fall in this category, modify section 95891(c) as follows:

(5) Wholesale Steam Sales. For covered entities who are under Long-term Steam Contracts to supply steam to an industrial facility that does not contain a clause to pass through the cost of compliance, allowances will be provided to the steam provider in the amount equivalent to what the industrial facility would have received if its emissions were covered in the industrial sector. (SMUD4)

Comment: SMUD recommends splitting the definition of "Long Term Contract" into two terms—reflecting Electricity and Steam Contracts. Modify section 95802(a)(156) and 157) as follows:

(156)"Long-Term Electricity Contract" means a contract for the delivery of electricity entered into before January 1, 2006 for the term of five years or more.

157)"Long-Term Steam Contract" means a contract for the delivery of steam entered into before January 1, 2006 for the term of five years or more. (SMUD4)

Comment: IEP remains concerned that the cap-and-trade regulations do not address the treatment of existing contracts, executed prior to the passage of AB 32, that do not have a reasonable means of recovering the cost of GHG allowances required for their continued operation. In general, obligated entities under the cap and trade program (e.g. IOUs, publicly owned utilities, industrial entities, refineries, etc.) are to be allocated free allowances to compensate them for the negative impacts of the GHG program on their market positions, regardless of whether they have a market in which they can pass along to consumers the costs of GHG allowances.

The only exception to this rule is the treatment of IPPs, which are all required to obtain allowances via an auction. For many IPPs this approach is acceptable as they have mechanisms available to recover or pass through the costs of GHG allowances. However, for a small subset of IPPs operating under existing contracts, currently no viable mechanisms exist within their existing contract structures to recover the cost of the GHG allowances they must obtain to comply with the Cap and Trade program. This lack of specific consideration in the cap and trade regulation regarding generators caught in these specific circumstances raises serious equity and consistency concerns. (IEPA3)

Comment: Both CARB and other agencies have noted the need for appropriate treatment of this limited group of contracts, yet to date, no remedy has been provided. Recognition of this issue dates back to the early work of the Market Advisory Committee. More recently, CARB itself acknowledged the problem in its Initial Statement of Reasons for the cap-and-trade program as well as subsequent summary documents for previous versions of the regulation. However, the most recent version of the regulation provides no consideration of this issue whatsoever.

CARB Staff has indicated its preference for resolution of this issue through contract renegotiation between contract counterparties; however, the counterparties to the IPPs have no incentive to renegotiate these contracts as these will be the only generation resources for which the electricity purchaser does not incur a carbon cost. A counterparty's ability to avoid these costs enables the buyer to garner windfall profits from the sale of the electricity in a market where the Market Clearing Price (MCP) contains a GHG value.

In the case of tolling agreements where a utility can call on or effectively "run" the generator, the utility will have an incentive not to renegotiate the contract. In fact, the utility has a perverse incentive to run such a generator more because the generator, without the ability to include cost recovery for GHG allowances in its price, will appear relatively cheaper than resources that include the cost of GHG allowances in their price, either through contract price or the wholesale market price. This distortion of the GHG price signal could lead to increased GHG emissions, contrary to the objectives of the cap-and-trade program (e.g. if a higher-emitting resource is dispatched ahead of a lower-emitting resource solely because the higher-emitting resource's price does not reflect the cost of GHG allowances).

In addition to the counterproductive emissions impacts, failure to address these contracts will also undermine CARB's policy for freely allocating allowances to the distribution utilities. The utilities get free allocation under the assumption that ratepayers incur GHG costs when the utility purchases power at wholesale, under bilateral contracts or through the utility's own compliance obligation for UOG. If the utility can avoid the GHG costs for some contracts, then it should not be receiving free allocation to cover the costs of GHG from generation resources with contracts that do not allow them to pass through the cost of GHG allowances. Since the utilities will receive direct allocation for costs they will not bear under long-term contracts, the fundamental emission reduction and cost allocation principles (i.e. CARB's policy rationale for direct allocation to the distribution utilities) will be undermined.

To avoid these detrimental impacts on the program, IEP requests that the Board explicitly recognize this problem and through Resolution provide affirmative direction that CARB will continue to evaluate the issue and provide a remedy for these affected IPPs before the first auction in 2012. Specifically, CARB should create a place for these affected IPPs to receive free allowances by reducing utility or industrial sector allocations when those allocations account for GHG emission costs that the utility did not incur due to a contract that was (1) executed before the passage of AB 32, and (2) that has no ability to recover GHG allowance costs. Alternatively, in instances where the counterparty does not receive free allocations, CARB should state that it will evaluate amendments to direct the compliance obligation to the entity (such as a marketer) that is able to recoup the GHG costs. (IEPA3)

Comment: The current cap-and-trade regulations do not provide a formalized transition process for facilities that can potentially convert from high carbon fuels to lower carbon fuels or technologies. Without a transition mechanism, the new cap-and-trade regulations, which will begin incorporating a carbon cost into the electric sector as soon as 2013, will discourage transitions to lower carbon systems, particularly where those higher transition costs cannot be passed through existing power and/or steam contracts. To avoid premature closure of these facilities and associated economic impacts on employees, related industries, and local economies and governments, CARB should amend the cap-and-trade regulation to allow a limited mechanism to support these plants during the conversion from high carbon fuels to lower carbon fuels or technologies. ACE Cogeneration, Rio Bravo Poso and Rio Bravo Jasmin have identified two methods for achieving such a conversion with respect to costs associated with electric sales. Either method would provide a workable transition path for these facilities. Each proposal includes language which could be incorporated into the cap-and-trade regulation. With respect to costs associated with thermal energy provided under contracts without cost recovery mechanisms, a similar approach should be included for provision to unaffiliated entities in the industrial sector in a way that reflects the contribution of the thermal energy input in the product-based benchmark. General language is proposed here because it is our understanding that the detailed benchmark calculations used for industrial assistance are held in confidence by staff. (ACERIO2)

Comment: Under the regulation, the operators of "third party" CHP facilities face stranded costs in terms of the emissions associated with the thermal, and in some cases retail electricity, provided to the host application under such legacy steam and/or electricity contracts.

The CCC, along with many other stakeholders, has repeatedly described the problem and proposed a variety of solutions. We were disappointed to see that the second 15-day modified rule remained silent on this issue. While parties can attempt to renegotiate existing contracts to enable cost recovery, the reality is that the CHP operator has no leverage in those discussions. Consequently a backstop is essential and in these comments the CCC offers another possible solution that would more accurately allocate allowances to the electricity sector, and preserve a set-aside of allowances for resolving the CHP legacy contract issue. The CCC agrees with the ARB staff proposal to allocate 89 MMT of allowances to the electricity distribution utilities (EDUs) based on the 2008 reported emissions pursuant to the ARB Mandatory Reporting Regulation (MRR) associated with electricity procured from non-CHP generators and importers of electricity. The CCC also agrees that the EDUs should be allocated allowances associated with electricity purchased from CHP generators. The CCC does not agree, however, that the CHP allowances should be based on the proposal by the Joint Utility Group (JUG). The CCC recommends instead that the allowances attributed to CHP should be based on the same MRR data used to calculate the 89 MMT from non-CHP sources. The value of the auction proceeds from these allowances should be distributed to consumers of electricity in a manner that does not discriminate against any supplier, including the supplier of electricity from a cogeneration facility that is consumed directly by an end user located on-site or on an adjacent parcel. The CCC further proposes that a portion of the remaining emissions reported from cogeneration should be made available as allowances for transition assistance to address the thorny and still unresolved issue of legacy contracts for CHP facilities that have no means to pass through the additional cost of AB 32 compliance. CCC agrees that negotiation between a CHP producer and its thermal or electric energy host is the preferred method to resolve the issue of legacy contracts; however there must also be a backstop for those situations in which negotiation is unsuccessful. This backstop should be designed to incent the affected parties to reach agreement rather than to rely on the backstop.

Pursuant to the MRR, each entity that reports GHG emissions associated with cogeneration as its primary or secondary sector, has already provided ARB with the data necessary to distribute emissions from cogeneration between wholesale electricity sold to an EDU for resale, electricity consumed by an end-user pursuant to California Public Utilities Code Section 218(b) and thermal energy consumed by a host. Allowances equal to 90 percent of the emissions associated with wholesale purchases of electricity should be allocated to the EDUs in addition to the 89 MMT associated with non-CHP sources. The source of data for emissions associated with purchases from CHP facilities would then be consistent with the source of data for electricity from non-CHP sources. The quantity of allowances available for allocation to EDUs and to the two special-use holding accounts described below will be subject to the cap adjustment factors in Table 9-2. Allowances equal to 90 percent of the remaining emissions from cogeneration should then be deposited into two special-use holding accounts under the control of the Executive Officer; one account reflecting emissions from retail electricity to address transition issues associated with legacy contracts for retail electricity and the other account for emissions associated with thermal energy. Beginning with budget year 2013, a cogeneration facility with a compliance obligation that is a party to an agreement to sell thermal energy to a non-affiliated thermal host that was executed prior to January 1, 2006 and does not allow the seller to recover GHG compliance costs, may apply for transition assistance. That application must include (i) a copy of all contracts dealing with the purchase and sale of thermal energy and (ii) an affidavit certifying (a) that the submitted contract(s) are a complete and accurate record of all relevant agreements between the parties, (b) that the parties have entered into good faith negotiations to revise the contract(s) to allow for the pass through of GHG compliance costs, and (c) the parties are unable to reach agreement. Copies of contracts may be submitted with a request for confidential treatment. Upon review and verification of the application and all supporting documents, ARB staff will approve the application and request that the Executive Director transfer allowances to the applicant equal to 75 percent of the compliance obligation of the applicant attributed to thermal energy. Additional requests may also be submitted for compliance years 2014 and 2015; However the maximum number of allowances that may be allocated for budget years 2014 and 2015 will be 50 percent and 25 percent, respectively, of the compliance obligation associated with thermal energy for that budget year. No further allowance allocations associated with transition assistance for legacy contracts will be made after budget year 2015. Transfers by the Executive Officer to the registered holding account of the applicant will be made by November 1st of the year following the year in which the compliance obligation was created. For any budget year in which the quantity of transition assistance allowances approved for all applicants exceeds the quantity of allowances allocated to the special-use holding account, the available quantity of allowances will be allocated on a pro rata basis. Any allowances in the special-use holding account in excess of the allowances approved for transition assistance in any budget year will be designated for sale at auction pursuant to section 95870(f). In the special case of a thermal host of an applicant approved for transition assistance that is eligible for EITE assistance pursuant to section 95870(e), an appropriate adjustment will be made to the counterparty's EITE allocation for that budget year to avoid a windfall gain by the host. The CCC proposes a comparable provision in the regulation to address legacy contracts between a cogeneration facility and a non-affiliated host for the sale of electricity pursuant to Public Utilities Code section 218(b) in which there is no provision for the seller to recover AB 32 compliance costs. (CACC3)

> **Response:** Most of the comments above fall outside the scope of the second 15-day changes to the regulation. Nevertheless, we recognize the difficult situation of contract renegotiation for generators and marketers in regard to the compliance cost. We do not agree with stakeholders it is our responsibility to make these parties whole, or move them toward realizing they are whole by providing the various options of transition assistance suggested in the comments. Generally, we believe contract negotiation discussions included which party would bear future costs, and the price agreed upon in the contract reflected this risk. Additionally, if we were to resolve the issue by including language that would make parties whole we would be interfering in potential future contract renegotiation, or negotiation between parties investigating and preparing potential funding to support a switch to fuels which emit less GHGs.
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> Some stakeholders such as IEP, Wellhead Electric, Starwood Power Midway LLC., Wildflower, and supported by the Panoche Energy Center suggest amendments to section 95834, "Disclosure of Beneficial Holding Relationships." Their suggestion would require an EDU to be obligated for contracts with no cost pass-through mechanism, as long as the contract was entered into before the signing of AB 32. These comments suggest that utilities party to long-term contracts enter into beneficial holding relationships with the other party to purchase and hold allowances for the generator's emissions, and then transfer allowances for these emissions to the generator's compliance account. Again, the comments are outside of changes described in the second 15-day changes to the regulation. However, we believe that, for these legacy contracts that include the IOUs as a party, these generators should continue to work through either the CPUC's GHG Cost Revenue or the Long-Term Procurement Plan proceedings. The scoping memo for the Order Instituting a Rulemaking (OIR) for the cost revenue proceeding includes reference to this situation for both QF and non-QF generators. Nevertheless, we also remind parties of the opportunity to voluntarily participate in a beneficial holding account pursuant to section 95834(a)(3). This provision allows EDUs to serve as the agent in a beneficial holding relationship for another registered entity, if there is a contract between the two parties for the delivery of electricity. Under the requirements contained in this provision the EDU may transfer compliance instruments to cover emissions attributed to the electricity under contract.

As discussed in previous responses, we do not want to interfere in potential re-negotiations of contracts. Some parties were able to renegotiate their contracts to include the cost of the GHG obligation. Additionally, for contracts that expired prior to January 1, 2013, the modification to the compliance obligation commencement date decreased the number of contracts that would be affected. ARB determined that it was necessary to get the market tracking, auction, and market oversight systems in place and operating prior to the commencement of the first compliance period. As a result, parties with contract terms ending prior to this date are now able to renegotiate the GHG cost.

For the other contracts, some entities were able to put many funding options and opportunities together and are investing in plant modifications to support switching to fuel sources; in particular, renewable fuel sources that are RPS eligible. RPS-eligible fuel sources provide an additional funding opportunity to support the fuel switching through the sale of RECs.

However, we acknowledge there are still parties that have not been able to determine a path to resolve GHG costs and are still not able to pass the costs through to consumers. The counterparty has no incentive to open up the contract. Some of these counterparties have fuel and other subcontracts which support the electricity generation. If contract renegotiation were to pass the GHG costs down from the generator, these parties would also have to open up their supporting contracts to pass costs down. For some of these contracts, the fuel costs agreed upon are a result of hedging fuel prices. Counterparties claim they could be stuck with the GHG costs because they are not able to renegotiate the fuel or other supporting contracts.

Constellation Energy for ACE Cogeneration, Rio Bravo Poso, and Jasmin facilities comment that these facilities will undergo modifications to support the transition to a fuel source that emits less GHGs than the current solid fuels. Constellation requests that the regulation be amended to include language for a limited mechanism to support projects that are transitioning fuels, such as the Rio Bravo Poso and Jasmin facilities. They include two options. However, as mentioned above, the suggested changes fall outside the scope of the second 15-day changes to the regulation. We acknowledge the options suggested by Constellation and suggest that Constellation approach the CPUC and/or Public Utility Boards, as this might be an opportunity for use of allowance value by the utilities.

The California Cogeneration Council (CCC) and PE Berkeley comments acknowledge the modifications made to section 95852.2 (c), which provides an exemption from a compliance obligation to military facilities. CCC and Wildflower suggest a similar exemption be extended to the emissions attributed to thermal energy or electricity sold to military facilities, to ensure equitable treatment. However, if the CHP operator is providing thermal or electricity to a military facility, the exemption we provide to the military does not prohibit the generator or CHP operator from passing costs down to the military facility. PE Berkeley, Inc. suggests a similar exemption for their facility because they supply electricity to PG&E and thermal energy to UC Berkeley. They claim they are in a unique situation in providing thermal energy to the UC campus because the contract, which expires in 2017, does not contain a cost pass through mechanism.

The CCC suggests an alternative methodology for assigning emissions for CHP. They propose that assigned emissions be based on the same 2008 MRR data used to calculate the 89 MMT from non-CHP sources. The value of the auction proceeds from these allowances would be distributed to consumers of electricity in a manner that does not discriminate against suppliers of electricity. We do not agree with this suggested use of allowance value, as it goes against the principles of the design of the program for the allowance value to be used to support AB 32 purposes, and not for direct rate relief. They further suggest that a portion of the remaining value be made available for transition assistance for parties that have contracts with no cost pass through provisions, as a backstop if the preferred approach of renegotiation does not come to fruition. We acknowledge this suggestion made by the CCC and PE-Berkeley, Inc. and note that the proposed change is outside of the scope of the modifications noted in the second 15-day changes to the regulation. Again, we point to the parties of the contracts to continue renegotiation.

Other commenters, such as IEP and Wildflower, propose resolution language to direct ARB staff to continue to work with stakeholders to ensure proper treatment of generators or CHP facilities with contracts entered into before the signing of AB 32 and which do not contain cost pass-through provisions. We acknowledge the proposed language.

While Calpine continues to work on contract renegotiation, they believe the best way to address the situation is for a direct allocation of allowances to the generators. At the minimum, they request us to revise the regulation so that if entities are identified to receive industrial assistance, and they have contracts with generators for thermal or electric energy, then they should not receive allowances for emissions attributed to this energy. We acknowledge this suggestion provided by Calpine and encourage the parties to continue to renegotiate contracts and to contact us if they need our assistance in facilitating discussions with the industrial parties.

IEP requests that the Board resolution recognize that this long-term contract issue is still an outstanding issue that needs to be further addressed, and they would like the Board to direct staff to continue to evaluate the situation and provide a remedy prior to the first auction. Specifically, IEP suggests that allowances be reduced from utility allocation for emissions from this generation, and if a counterparty is identified as an entity to receive free allowances, then the resolution should state that ARB staff will draft amendments to direct the obligation to the entity that is able to recoup the GHG costs. Again, we disagree with this position that it is ARB's responsibility to make all of the parties whole.

Western Power Trading Forum requests that we establish a process and define conditions under which a generator would be eligible for assistance to recover costs. WPTF requests us to facilitate contract renegotiation or to provide free allocation to the affected party to cover emissions associated with the contract, if renegotiation is not successful. As mentioned above in the response to Calpine, we are available to assist and facilitate renegotiation discussions with parties.

In summary, we acknowledge this difficult position for some parties that are not yet experiencing success in the renegotiation process of these long-term contracts. We are encouraged by the numbers of contracts that have been successful in renegotiation. These parties are supporting a successful California cap-and-trade program by implementing our design intent through the renegotiation of these contracts so that the costs can appropriately be passed down to the end-user. For parties that have not been successful with renegotiation, we will provide support by facilitating discussions between parties so that they too will be able to support a successful program. We also encourage entities that have contracts with EDUs to approach the appropriate governing board or oversight agency and seek relief through their process. We remind utilities of the opportunity to voluntarily participate in the beneficial holding relationship that allows the EDUs to cover an obligation for emissions under contract for the delivery of electricity.

In Resolution 11-32, Board directed the Executive Officer to monitor progress on bilateral negotiations between counterparties with existing contracts that do not have a mechanism for recovery of carbon costs associated with cap-and-trade for industries receiving free allowances pursuant to section 95891, and identify and propose a possible solution, if necessary. For fixed-price contracts between independent generators and investor-owned utilities, the Board further directed the Executive Officer to work with the California Public Utilities Commission to encourage resolution between contract counterparties.

I-51. Comment: Air Liquide and other industrial gas manufacturers operate hydrogen production facilities in California that supply hydrogen to petroleum refineries under long-term, fixed-price contracts with terms of 15 to 20 years. Some of these contracts were signed years before the passage of AB 32 and before the parties could reasonably have anticipated AB 32's requirements. Because they significantly pre-date AB 32, these contracts may not allow the seller to pass on the costs that will be imposed on greenhouse gas emissions under the proposed Cap-and-Trade program. The September 12 draft does not address the economic dislocations that would occur as a result of such contracts. CARB has previously stated its intention to address long-term contracts in other sectors. In the Initial Statement of Reasons for Adoption of the Cap-and-Trade Rule, CARB recognized the importance of protecting parties to long-term electric power supply contracts, noting that some of those contracts, entered into before the mid-2000s, “do not include provisions that would allow full pass-through of cap-and-trade costs,” and may therefore “require special treatment” under the Cap-and-Trade Rule. This recognition is also reflected in federal Cap-and-Trade proposals, including Waxman-Markey (H.R. 2454) and Kerry-Boxer (S. 1733) legislation, as well as in the Regional Greenhouse Gas Initiative (RGGI), all of which included provisions to provide allowances to certain facilities subject to long-term contracts that did not allow the recovery of the costs of purchasing allowances at auction. CARB should make good on its statements of its intentions and address long-term contracts explicitly. Some CARB staff have expressed the view that Air Liquide and other covered entities that entered into long-term, fixed-price contracts knowingly assumed the risk of changes in the regulatory environment when they did so, and therefore CARB need not address long-term contracts. Air Liquide agrees that contracting parties ordinarily assume the risk of changes in environmental regulations, but the Cap-and-Trade Rule is different in two crucial respects:

- It is specifically designed to change the price terms on which covered entities, such as Air Liquide, based their contracts.
- Because the Cap-and-Trade Rule is designed to change behavior, by promoting efficiency and reducing emissions, through a price-changing mechanism, the magnitude of the likely price effect is huge by comparison with other environmental regulations.

The Cap-and-Trade Rule is unlike other government regulations (for example, workplace safety regulations) which have incidental and usually small effects on prices. The Cap-and-Trade Rule is explicitly designed to impose a price on CO_2 emissions that will be incorporated into the price of products produced by covered entities and that will alter the economic behavior of market participants. The Cap-and-Trade Rule is therefore an intentional interference with the market pricing mechanism, not simply a regulation of a health, safety or environmental matter that may have incidental effects on the market. Because the Cap-and-Trade Rule is an intentional change in the economic terms affecting contracting parties, CARB has an obligation to make sure that it is implemented fairly. There is a simple solution to the economic dislocations that might result from the Rule in its present form. CARB should permit covered entities subject to long-term contracts that do not allow the pass-through of carbon costs to retain a 100 percent industry assistance factor for the life of the current contract, or until it is amended to modify the price and supply terms. Such allowances may be limited, as Calpine has proposed in previous comments to CARB, such that they may not be traded or banked, thus eliminating any possibility of a windfall to contracting parties. If CARB does not act to protect parties to long-term contracts, contracting parties such as Air Liquide may be subject to large losses caused by contractually-required sales at fixed prices that do not account for carbon costs. The environment will not benefit, because the purchaser will not be subject to any increased price associated with carbon emissions, and will have no incentive to reduce its use of carbon-emitting products. The Cap-and-Trade program will also be damaged, because the failure to address long-term contract will create public examples of significant economic dislocations caused by an otherwise laudable program. To the extent that job losses may result, such losses will further damage the program. If CARB fails to address the long-term contracts covering California facilities, which are limited in number and easily addressed, the Cap-and-Trade Rule will produce market advantages for certain companies based not on their facilities' relative efficiency, but instead on the number of years they have committed to serve a particular customer—an arbitrary distinction that has no relation to the efficiencies that the Cap-and-Trade Rule is designed to foster. This market distortion will not serve the intent or further the goals of the Cap-and-Trade program or AB 32. CARB should therefore direct staff to prepare amendments to the Rule that will provide industry assistance to parties that entered into long-term contracts and that are unable to pass through the cost of GHG allowances. (ALLI2)

Response: Air Liquide claims we should provide one hundred percent transition assistance for industrial parties that are not able to pass costs through due to contract provisions that lack a mechanism to do so. We do not agree with Air Liquide that we should provide this type of assistance. Our program was not "… designed to change the price terms." The price terms are contained in the contract between the parties. Contracts vary to include, or not, provisions to accommodate changes to reflect increase or decrease costs due to changes in fuel costs, environmental factors, or regulatory requirements. Whether contracts do, or do not, contain these provisions is up to the parties. Therefore, Air Liquide's statement is not true that our program was designed to change terms. Our design was not specifically tailored to change price terms. Our design intent is for the cost to be passed down to the end-users. Many contracts have provisions which allow for a re-opening of the contract to pass-through environmental regulatory costs, or other costs.

Air Liquide also claims "Because the Cap-and-Trade Rule is designed to change behavior, by promoting efficiency and reducing emissions, through a price-changing mechanism, the magnitude of the likely price effect is huge by comparison with other environmental regulations." We do not agree with Air Liquid. To the extent that efficiency has or has not already been incorporated into the product, then that price effect will vary also. Another variable is the extent the product inherently results in GHG emissions, the opportunities available for the incorporation of efficiency, and the possibility of changing operations for the manufacturing or production of a product in which less GHGs are emitted. The effect could therefore be minimal, or it could be just as much or more than other environmental regulations. It is not our intent to create a market distortion, but a distortion is a result of the status of a certain product prior to the implementation of the regulation. Those that were anticipating, since the signing of AB 32, that the price of carbon would be accounted for in the economy will be most likely to be least affected. If there was implementation of early action, these entities will be best situated at the start of the program. Those early actions would include renegotiating a contract, the investigation and preparation for switching to a fuel source that results in less GHGs being emitted, or implementing efficiencies to reduce GHG cost.

We do not agree that there should be one hundred percent transition assistance due to the inability to pass the cost of compliance down. This would not support the methodology used to determine allowances allocated to the industrial sector. We developed this approach to benchmark stringency after careful analysis of California emissions intensity data and approaches used in other successful cap-and-trade programs. In selecting benchmark stringency we are balancing the need for providing adequate transition assistance and minimization of leakage with meeting the emission reduction goals of AB 32 and prevention of windfall profits through excessive free allocation.

Within each sector, the most efficient facilities with efficiencies better than the benchmark, will be receiving more allowances than they will need and can sell their excess allowances. Less-efficient facilities will need to purchase allowances to fulfill their compliance obligation. Beyond the initial allocation period, the level of free allowances will decline through the use of a cap declining factor and an assistance factor. Because allowances can be traded, the program provides incentives for those with the most cost-effective reduction opportunities to reduce emissions quickly. If we were to provide one hundred percent assistance to industries that could not pass the cost down due to contact issues would skew the incentive for those entities that have strived to be early actors and have made an extended effort to be more efficient. We believe that the contract terms that do not include cost pass-through mechanisms negotiated these terms and conditions and the cost agreed upon reflect the risks taken by one party or the other.

Allocation

I-52. Comment: The University of California (UC) was deeply disappointed by California Air Resources Board's (CARB) draft rulemaking of September 12, 2011. If adopted, this rulemaking will require UC to purchase 100 percent of its allowances starting in year one of the cap-and-trade program at an annual cost of $7-$28 million, or more. The purchase of allowances imposes significant added costs on University operations at a time when State General Fund support for the UC has been reduced by over $1.2 billion in the last 4 years. The University of California supports the goals of AB 32 and has never sought an exemption from the cap-and-trade program. However, the University believes that public entities that are regulated under cap-and-trade should be treated no worse than industrial facilities and utility companies. For the last two years, the University has tried to work with CARB to develop a compliance path that maintains the cap-and-trade program's integrity while minimizing its negative impacts on the University of California's teaching, research, and public service missions. Building on previous discussions with CARB, the University proposes the following:

- UC campuses that are directly regulated under cap-and-trade will be required to submit a five-year plan to CARB that details anticipated investments in greenhouse gas (GHG) abatement.

- Pending CARB's approval of these plans, regulated UC campuses will receive an allocation of allowances sufficient to cover 100 percent of their surrender obligation for the duration of the cap-and-trade program.
- In exchange for this free allocation, CARB will require regulated UC campuses to invest a sum commensurate to 125 percent of the market value of the freely allocated allowances in projects that abate Scope 1 and Scope 2 GHG emissions.
- UC will also commit to reducing its regulated emissions by 7 percent by 2020. This is in line with the overall, state-wide emissions reduction that CARB is targeting with its cap-and-trade program.

The proposal reflects the University's deep commitment to reducing its own carbon footprint. In exchange for the ability to invest compliance dollars in real abatement projects, UC is willing to invest a sum greater than what it would otherwise expect to pay to purchase allowances at auction. Moreover, as a capped sector entity, the University is willing to commit to achieving its proportional share of emissions abatement.

In communications with the University, CARB has expressed concern that accepting UC's proposal will open a Pandora's box and that countless other regulated entities will demand similar accommodation from CARB. CARB's fears are unfounded. In the unlikely event that there are other regulated entities willing to spend more on abatement projects than they would otherwise spend on allowances, and are further willing to commit to a seven percent reduction in surrender obligation by 2020, there is no downside for CARB allowing them to do so.

Over 90 percent of UC's anticipated compliance costs are the direct results of its investment in combined heat and power (CHP) plants. Were it not for these CHP plants, most of the UC sites that are regulated under cap-and-trade would not be facing carbon costs for natural gas usage until 2015. Thus, CARB's rulemaking imposes a penalty for early adopters of CHP, an outcome that directly contradicts the AB 32 Scoping Plan, which expressly encourages increased use of CHP as a major abatement measure. In recent months, CARB has offered the assurance that UC campuses with CHP plants will have access to the allowance value that is being allocated to the State's electric utilities for the benefit of end-use customers.

Even if the utility companies and CPUC were inclined to return this allowance value to self generators like UC, it would be challenging for them to do so because emissions from UC's CHP plants are not included in the allowance allocation that utilities will receive from CARB. The simplest way to remedy this shortcoming would be to allocate allowance value to self-generators, since they effectively function as both a utility and an end-use customer. Barring this approach, CARB should at least include emissions from CHP plants that serve onsite load when determining allowance allocations to utility companies. Lastly, for the record the University hereby incorporates by reference the comments contained in its previous letters to you dated December 3, 2010 from Senior

Counsel Anthony Garvin and August 10, 2011 from Senior Vice President Dan Dooley. (UC4)

> **Response:** While we understand the concerns of the University of California, we expect that the university will be able to fully pass the cost of carbon to campus energy users. With no risk of GHG emissions leakage, the university does not require free allocation. Specifically, we note that UC is requesting free allocation for emissions associated with their combined heat and power plants. At this time, we believe a free allocation would be inappropriate and would bestow favored treatment upon the university, as other independent combined heat and power producers will not receive any form of free allocation. That is, the treatment of UC combined heat and power facilities will be exactly similar to the treatment of independent combined heat and power facilities serving the electricity market.
>
> While free allowances for their direct emissions would be inappropriate, the university should expect to receive some remuneration for the increased cost of procuring electricity from the local distribution utilities that service the campuses. We are working closely with the CPUC and the POU governing boards to determine the appropriate level of remuneration.
>
> In addition, Board Resolution 11-32 directs the Executive Officer to monitor progress on bilateral negotiations between counterparties with existing contracts that do not have a mechanism for recovery of carbon costs associated with cap-and-trade for industries receiving free allowances pursuant to Section 95891, and identify and propose a possible solution, if necessary. For fixed-price contracts between independent generators and investor-owned utilities, the Board further directs the Executive Officer to work with the California Public Utilities Commission to encourage resolution between contract counterparties. Board Resolution 11-32 also directs the Executive Officer to coordinate with the State universities and stakeholders to evaluate options for compliance, with amendments to the regulation as appropriate, including options of the use of auction revenue and report back to the Board in summer of 2012.

I-53. (multiple comments)
Comment: Restrictions on use of allowance value should be deleted or revised. Section 95892(d)(5) (p. 143) prohibits the use of allocated allowances to meet compliance obligations for electricity sold into the California Independent System Operator (CAISO) markets. Section 95892(d)(5) provides that "Use of the value of any allowance allocated to an electrical distribution utility, other than for the benefit of retail ratepayers consistent with the goals of AB 32 is prohibited, including use of such allowances to meet compliance obligations for electricity sold into the California Independent System Operator markets." As written, with the phrase "including use of such allowances to meet compliance obligations for electricity sold into the California Independent System Operator Markets" at the end, section 95892(d)(5) would have the unintended consequence of unduly discriminating against publicly-owned utilities

("POUs") that are members of the CAISO. The section should be deleted or revised to avoid the undue discrimination. Prohibiting the use of allowances to meet compliance obligations for electricity sold into the CAISO would discriminate against POUs that are members of CAISO.

The prohibition on using allowances allocated to POUs to meet their compliance obligations for electricity that POUs generate and sell into the CAISO would discriminate against the POUs that are members of the CAISO. Under section 95890(b) of the Regulation, all electrical distribution utilities will receive a direct allocation of allowances if they comply with the MRR. Under section 95892(b), POUs may direct the ARB Executive Officer to place their allocated allowances in their compliance accounts. POUs that are not members of the CAISO may use the allowances that the Executive Officer places in their compliance accounts to meet their compliance obligations. In fact, their allocated allowances may not be withdrawn from their compliance accounts for any other purpose.

The situation is different for POUs that are members of the CAISO. A peculiarity of the CAISO is that CAISO members are required to sell the electricity they generate or import into the CAISO market and then bid the electricity back in the wash transaction in order to use the electricity that they generate or import to serve their native load. Due to section 95892(d)(5), CAISO POUs would not be able to direct the Executive Officer to place their allocated allowances in their compliance accounts to meet their compliance obligation. If the allowances were place in their compliance accounts, section 95892(d)(5) would bar them from using their allowances to meet their compliance obligation for the electricity they sell into the CAISO market and then buy back to serve their native load. The CAISO POUs would have to have their allowances placed in limited use holding accounts and sent to auction. Thus, as written, section 95892(d)(5) would discriminate against POUs that are members of the CAISO in comparison to non-CAISO POUs solely because they are members of the CAISO.

The discrimination against CAISO POUs would be an unintended consequence of section 95892(d)(5) as currently drafted. The discrimination that section 95892(d)(5) would impose on CAISO POUs is an untended consequence of the section as currently drafted. The ARB climate change staff has made it clear to SCPPA that the prohibition on using allowances to meet compliance obligations for electricity sold into the CAISO is intended to mean that if a POU elects to elect to have its allocated allowances placed in its limited use holding account rather than its compliance account and then sells the allowances, the monetary value of the allowances may not be used to meet the POU's compliance obligation for generation that is sold into the CAISO market. Staff has confirmed to SCPPA that the reference to "the value of any allowance allocated to an electrical distribution utility" in section 95892(d)(5) means the money that a utility receives after auctioning administratively allocated allowances that are placed in its limited use holding account. Thus, under the staff's interpretation, if a CAISO POU directs the Executive Officer to place its allocated allowances in its compliance account, it may use the allowances to cover its compliance obligation just like a non-CAISO POU. While SCPPA is pleased by the climate change staff's interpretation of section

95892(d)(5), SCPPA is concerned that at some future time staff members in the ARB's enforcement branch may interpret this section differently.

Section 95892(d)(5) as currently written might be interpreted to prohibit the use of allocated allowances to meet a POU's compliance obligation for electricity sold into the CAISO. In spite of the climate change staff's interpretation of section 95892(d)(5) as currently written, the section is susceptible to being interpreted differently. Although the staff has told SCPPA that the section only prohibits the use of revenue derived from auctioned allowances to cover the compliance obligation of electricity sold into the CAISO, that interpretation appears to be contradicted by the wording in other parts of section 95892. Elsewhere in section 95892 the term "auction proceeds" is used to refer to revenue from auctioned allowances. The term "allowance value" is used to refer to the value of allocated allowances that are placed in a utility's compliance account and used for compliance rather than being auctioned. For example, section 95892(e) refers to "auction proceeds" in sections (1) and (2) and separately refers to the "value of allowances, deposited directly into compliance accounts" in sections (3) and (4). Section 95892(d)(3) and the first paragraph of section 95892(e) refer to "auction proceeds and allowance value" conjunctively, indicating that each phrase has a separate meaning and that both meanings are addressed in those sections.

Likewise, the Second 15-Day Change Notice distinguishes between "the use of auction proceeds from the sale of allowances" and "the value of allowances freely allocated and used for compliance" in discussing the proposed changes to section 95892(d). Section 95892(d)(5) uses the phrases "allocated allowance value" and "value of any allowance allocated" to a utility and refers to the "use of such allowances to meet compliance obligations." There is no reference to "auction proceeds" in this subsection. Thus, section 95892(d)(5) as currently drafted is susceptible to being interpreted to provide that allowances that are allocated to a CAISO POU and placed in that POU's compliance account cannot be used to meet that POU's compliance obligation.

Section 95892(d)(5) should be deleted or revised to eliminate the unintended consequence of discriminating against CAISO POUs.

Section 95892(d)(5) should be revised to eliminate the unintended consequence of discriminating against CAISO POUs. There are several options for remedying the discriminatory effects of section 95892(d)(5).

Option 1: Delete section 95892(d)(5) in its entirety.
One solution would be to delete section 95892(d)(5) in its entirety. Section 95892(d)(5) is superfluous. Section 95892(d)(3) mandates that both auction proceeds and allowance value "shall be used exclusively for the benefit of retail ratepayers" and not for other purposes:
(3) Auction proceeds and allowance value obtained from an electrical distribution utility shall be used exclusively for the benefit of retail ratepayers of each electrical distribution utility, consistent with the goals of AB 32, and may not be used for the benefit of entities or persons other than such ratepayers.

Thus, section 95892(d)(5) restates as a prohibition which is stated affirmatively in section 95892(d)(3). To the extent that section 95892(d)(5) is redundant, deleting it would be a "nonsubstantial" change under section 11346.8(c) of the Government Code that would not require a further opportunity for 15-day comment.

Option 2: Revise section 95892(d)(5) to limit its applicability to the value of allowances placed in limited use holding accounts.
The second option would be to revise section 95892(d)(5) to reflect the climate change staff's understanding that the section applies only to the use of allowance value associated with allowances that are placed in limited use holding accounts rather than compliance accounts:

Section 95892. Allocation to Electrical Distribution Utilities for Protection of Electricity Ratepayers.
(d)(5) Prohibited Use of Allocated Allowance Value. Use of the value of any allowance allocated to an electrical distribution utility and placed in the electrical distribution utility's limited use holding account, other than for the benefit of retail ratepayers consistent with the goals of AB 32 is prohibited, including use of such allowance to meet compliance obligations for electricity sold into the California Independent System Operator markets.
This revision would be a "nonsubstantial" change under section 11346.8(c) of the Government Code. It merely conforms the wording of section 95892(d)(5) to the staff's understanding of the meaning of section 95892(d)(5).

Option 3: Revise section 95892(d)(5) to refer to "auction proceeds."
An alternative approach to conforming section 95892(d)(5) to the climate change staff's understanding would be to revise the section to refer to "auction proceeds" instead of "allowance value." This would limit the scope of the section to allowances that are placed in a utility's limited use holding account and would be consistent with the terminology used in other subsections of section 95892:

Section 95892. Allocation to Electrical Distribution Utilities for Protection of Electricity Ratepayers.
(d)(5) Prohibited Use of Auction Proceeds. Use of auction proceeds obtained by an electrical distribution utility, other than for the benefit of retail ratepayers consistent with the goals of AB32 is prohibited, including use of such proceeds to meet compliance obligations for electricity sold into the California Independent System Operator markets.

As with the second option, this would be a "nonsubstantial" change under section 11346.8(c) of the Government Code, insofar as it does nothing more than conform the wording of section 95892(d)(5) to the staff's understanding of what is meant by section 95892(d)(5).

Option 4: Revise section 95892(d)(5) to exclude native load. A fourth option would be to revise section 95892(d)(5) as proposed in SCPPA's comment submitted to the ARB on August 11, 2011, to allow CAISO POUs to use their allocated allowances to meet their compliance obligation associated with the electricity they generate or import to serve their native load:

Section 95892. Allocation to Electrical Distribution Utilities for Protection of Electricity Ratepayers.
(d)(5) Prohibited Use of Allocated Allowance Value. Use of the value of any allowance allocated to an electrical distribution utility, other than for the benefit of retail ratepayers consistent with the goals of AB32 is prohibited, including use of such allowances to meet compliance obligations for electricity sold into the California Independent System Operator markets in excess of the electricity needed to meet the electrical distribution utility's native load in the same hour.

Absent deletion or revision, 95892(d)(5) should be addressed in a rulemaking in 2012. If the ARB concludes that the changes discussed above cannot be made at this stage because they would require further 15-day public comment, the ARB should address this issue in a supplemental rulemaking in 2012. To this end, the Resolution should include the following statement:

BE IT FURTHER RESOLVED THAT the Board directs the Executive Officer to initiate a public process for the revision of section 95892(d)(5) no later than February 2012, to ensure that this provision allows POUs to use allowances that are placed in their compliance accounts to meet the compliance obligation associated with the electricity they generate or import to serve their native load.

The resolution should clarify that a POU can direct the executive officer to place a portion of its allocated allowances in another utility's account in certain circumstances under section 95892(b)(2). SCPPA appreciates the efforts of ARB staff to accommodate the particular circumstances of POUs in the provisions on the allocation of allowances to utilities, in particular the situation exemplified by the Magnolia generating facility in Burbank, California. Magnolia is owned by SCPPA, a joint powers authority, but it is operated by Burbank Water & Power ("Burbank"). Burbank rather than SCPPA will have the compliance obligation for Magnolia. As such, Burbank will need to have the other SCPPA members that participate in Magnolia direct the Executive Officer to place a share of their directly allocated allowances into Burbank's compliance account to cover their share of Burbank's compliance obligation for Magnolia. Section 95892(b)(2) (p. 141) appears to permit SCPPA members to direct the Executive Officer to place a share of their allowances in Burbank's account to meet the Magnolia compliance obligation. Section 95892(b)(2) provides:

> (2) Publicly Owned Electric Utilities or Electrical Cooperatives. When allocating to a publicly owned electric utility or an electrical cooperative, the Executive Officer will place allowances in either a limited use holding account or in a compliance account per the entity's preference. Prior to receiving a direct allocation of allowances, publicly owned electric utilities or electrical cooperatives will inform the Executive Officer of the share of their allowances that is to be placed:

(A) In the compliance account of an electrical generating facility operated by a publicly owned electric utility, an electrical cooperative, or a Joint Powers Agency in which the electrical distribution utility or electrical cooperative is a member and with which it has a power purchase agreement; or

(B) In the publicly owned electric utility's or electrical cooperative's limited use holding account. … However, the Second 15-Day Change Notice states that section 95892(b) was amended to clarify that POUs "may only ask for allocations to be placed into compliance accounts of facilities they (or a Joint Powers Agency) operate." This summary of the changes to section 95892(b) is more limited than the actual language in section 95892(b)(2), and it would not accommodate the Magnolia situation. Neither SCPPA nor the non-Burbank SCPPA POUs operate Magnolia. Thus, under the summary, the non-Burbank SCPPA POUs would not be able to direct the Executive Officer to place allowances in the Burbank compliance account to cover Magnolia emissions.

SCPPA is concerned that the restrictive summary in the Second 15-Day Change Notice could result in a misinterpretation of section 95892(b)(2) in the future. To avoid the possibility of misinterpretation, SCPPA requests that the Resolution include the following statement to correct the public record:

WHEREAS, pursuant to section 95852(b) of the [Cap and Trade Regulation], publicly-owned electric utilities may direct the Executive Officer to place a share of their allowances in the compliance account of the operator of an electricity generating facility that delivers electricity to multiple utilities. (SCPPA8)

Comment: The Proposed Regulation includes specific limitations on the use of both auction revenues and allowance value in sections 95892(a) and (d)(3), as well as requirements to annually report to the Executive Officer regarding the use of those allowances and value. These provisions are applicable to all electrical distribution utilities. However, the Proposed Revisions also include a prohibition that singles out compliance entities that are located within the California Independent System Operator (CAISO) for disparate treatment and has the potential to hinder wholesale electric transactions. Section 95892(d)(5) prohibits the use of allowance value "to meet compliance obligations for electricity sold into the California Independent System Operator markets." This provision should be stricken, as it fails to recognize the manner in which energy transactions through the CAISO Balancing Authority work.

For example, entities such as NCPA, who have transactions that must be scheduled through the CAISO Balancing Authority, including self-scheduled energy that is delivered directly to load, this prohibition would place an unreasonable constraint on utility operations. Due to the CAISO's rules for scheduling and bidding, tracking the various permutations of such transactions would be virtually impossible. Further, POUs located in the CAISO Balancing Authority must sell all of their self-owned generation into the CAISO markets, and then purchase the electricity back, even if it is for the exact same quantity of electricity. The provisions of section 95892(d)(5) would preclude these entities from being able to use allowance value to meet their compliance obligations associated with the production of this electricity. This provision places an undue and unwarranted restriction on entities that are mandated to participate in the ISO markets, with no resulting benefit to the underlying intent of the Proposed Regulation to ensure that allowance value is used "for the benefit of retail ratepayers consistent with the goals of AB 32." Accordingly, NCPA urges CARB to strike section 95892(d)(5) it in its entirety. (NCPA4)

Comment: Section 95892(d)(5) uses the terms "allowances" and "allowance value" interchangeably, with the phrase "such allowances" referring back to the "value of any allowance." SCE is concerned that this section, if interpreted broadly, could prohibit the use of any allowance revenues to meet compliance obligations for any electricity that is sold into the CAISO, which would include all utility sales. This is clearly not the intent. The below modifications will ensure that there is only a prohibition on the use of allowances (not allowance value) for meeting compliance obligations for electricity sold into the CAISO. Modify section 95892(d)(5) as follows:

(5) Prohibited Use of Allocated Allowance Value. Use of the value of any allowance allocated to an electric distribution utility, other than for the benefit of retail ratepayers consistent with the goals of AB 32 is prohibited. ~~,including use of such~~

Prohibited Use of Allocated Allowances. Use of any allowances to meet compliance obligations for electricity sold into the California Independent System Operator Markets is prohibited. (SCE4)

> **Response:** Section 95892(d)(5), which was formerly section 95892(f), imposes specific prohibitions on some uses of freely allocated allowances and auction proceeds. The intent of this language is to guarantee that all bids into the CAISO markets correctly include the generator's emissions cost in the generator's CAISO market bid price. Specifically, POUs that wish to transfer allowances to generators that sell into the CAISO market will have to purchase those allowances at the allowance auction or in the secondary market to ensure that the transferred allowance is correctly valued and that freely allocated allowances are not used to suppress CAISO bid prices.
>
> POUs are able to use their freely allocated allowances to directly meet the compliance obligation for generators that do not sell into the CAISO market. We understand that some generators controlled by POUs may sell their electricity into the CAISO market and then purchase it back out of the market to meet their load, due to transmission constraints. We do not consider this a special case. The POUs may not transfer freely allocated allowances to meet the compliance obligation of those generators involved in these wash transactions.
>
> SCPPA provides four options to resolve their issue with the requirements contained in section 95892. They indicate that they have a concern about the provisions contained in section 95892 in regard not to our interpretation of the provisions, but how the enforcement team might interpret the provision. We

assure SCPPA that ARB staff have and will continue to work together on all aspects of the regulation, including verification and enforcement.

We do not agree that modification is needed and do not agree that the options provided by SCPPA would improve the regulation. They first suggest that we delete section 95892(d)(5) because it is repetitive to the provision contained in section 95892(d)(3). We do not believe that section 95892(d)(5) is repetitive. We believe that the inclusion of section 95892(d)(5) is necessary to explicitly prohibit the use of allowance value for covering the emissions or allowance costs associated with electricity sold into the CAISO market. Without this expressed provision, it would be entirely possible for an EDU to purchase allowances to cover a compliance obligation for sales of electricity into the CAISO market and then to argue that it was an appropriate use of value and a benefit to ratepayers. Further, the inclusion of section 95892(d)(5) is essential to avoid distortions in the CAISO market associated with incomplete carbon pricing.

SCPPA's second proposed option is to revise the section to limit the application of section 95892(d)(5) to the "value" of allowances placed into the limited use holding account. We did not make this change, as we believe it is important that the section applies not only to freely allocated allowances but also to the allowance value, a category that includes proceeds from the sale for freely allocated allowances. The utilities are prohibited from using their freely allocated allowances, and the value from the sales of these allowances, for electricity sold into the CAISO market. Sellers into the CAISO market will, if bids are appropriately entered, already receive compensation for their carbon costs, which should be used to cover their carbon obligation. The allowances we provide to the utility is to be used for the benefit of ratepayers and to further the goals of AB 32. The third option is similar to the second option, except that the third option suggests that the limitation apply to the use of the allowance, rather than its value. Again, this change would be inappropriate, as it could eventually cause a distortion in the CAISO market.

The fourth option is to limit the provision to the sales into the CAISO market in excess of the electricity needed to meet native load. We believe that section 95892(d)(5) needs to apply to all of the electricity sold into the CAISO market in order to guarantee that electricity is efficiently dispatched and that the wholesale market includes appropriate carbon pricing. Exempting a quantity equivalent to the native load sold into the CAISO market could result in significant distortions in dispatch and improper uses of allowance value.

We understand that the provision will require some concerted effort on the part of the utility that is required to sell the electricity they generate or import into the CAISO market and then bid the electricity back in a wash transaction, in order to use the electricity they generate to serve their native load. SCPPA is correct; the utility will need to keep accurate accounting for purposes of meeting verification requirements. However, we believe this effort is necessary and justified in order to guarantee the integrity of the cap-and-trade program. Again, we will work to ensure that the regulation is interpreted correctly, and that the utilities receive guidance on evidence that will satisfy verification that the provision has been met satisfactorily, if needed.

Water

I-54. (multiple comments)
Comment: ARB's goal of providing carbon price signals to the end-user will be met by the SWP. However, ARB's goal of mitigating for price increases cannot be met under ARB's current plan to provide the free allocations associated with SWP load to electric distribution utilities. This goal can be met by providing those free allocations to the State Water Contractors in proportion to their energy charges from the SWP. This approach will meet ARB's goals and provide equity and protection to SWP water users. Add section 95890(c) as follows:

> (c) All provisions of this Article applicable to a publicly-owned Electric Distribution Utility shall be applicable to the Contractors of the State Water Project pumping load reported under article 2, section 95111(e), title 17, Greenhouse Gas Emissions Data Report. Where these Contractors are not Water Distribution Utilities, the Allocation provided to the individual Contractor shall be held in trust for its member water distribution utilities**.** (SWC4)

Comment: In the Second Notice of Public Availability, staff noted that language was removed from section 95892(d)(3)(B) and (C) that had indicated particular requirements for use of auction proceeds from the sale of free allowances. Staff noted that ARB does not have authority to appropriate funds, and that the use of revenue obtained from consignment of allowances is the responsibility of the PUC for investor owned utilities and the governing Boards of publically owned utilities. Revising the past decision to conform to the most recently revised language reflecting ARB staff's recent recognition of the financial responsibilities of public utility boards is not only appropriate and consistent, but it also removes a serious inequity and allows the regulation to meet the Board's adopted policy of being economically neutral. As the proposed regulations currently stand, water pumping by the SWP is the only water source that has not received the appropriate allocation of free allowances, and thus does not have the benefit of mitigation from rate shock and protection in the case of market failure. In particular, as the regulations now stand, the lack of provision of allowances to SWC agencies will have the following outcomes which are contrary to Board policy. The proposed regulations are inequitable to SWP‟s customers and will result in an unmitigated rate shock to retail customers of SWC agencies; a transfer of income from southern to northern California; impairment of the ability of SWP water users to compete with those in similar industries; "leakage" of carbon emissions from California industries to those competitors outside the state; and lack of protection for SWP water users in the event of market failure. In conclusion, the currently-proposed language changes reflect appropriate recognition by ARB staff of the organizations that bear the responsibility for determining suitable treatment of emission allowance revenues. However, these changes are inconsistent with ARB's previous decision to withhold free allocations of allowances from SWP water users. To correct this inconsistency, to provide equitable rate shock mitigation to SWP water users, and to meet Board policy objectives, allocations of allowances should be provided to SWP water users. (SWC4)

Comment: In the absence of an exemption or deferral, providing free allowances to Metropolitan is the only equitable alternative. In the absence of a decision to exclude Metropolitan from the category of "covered entities" or to defer our compliance obligations until water sector-specific measures are formulated, the only equitable alternative is an allocation of free allowances. Metropolitan agrees with the ARB's apparent conclusion that we are distinct from the EDUs in important respects. However, it is fundamentally unfair for ARB to treat publicly-owned providers of a critical public resource in the exact same manner as for-profit marketers and, thereby, deny these providers and their customers any sort of price relief. In other words, if the ARB decides to impose the same compliance obligation on Metropolitan that it imposes on energy marketers and EDUs that import energy, it should protect Metropolitan's customers in the same manner that it protects the customers of the EDUs.

The inequity inherent in ARB's free allowance allocation approach is evident in a comparison with Metropolitan's member agencies that serve retail electric load. Many of these agencies have entitlements to energy resources outside of California. As importers, they will be required to acquire allowances to cover the emissions associated with this energy. This activity does not, however, result in these EDUs being characterized as "marketers," which are not entitled to receive free allowances. In addition, although these retail electric utilities will be able to use the free allowances they receive as EDUs to offset costs to their retail electric customers, as purchasers of Metropolitan water they will be unable to mitigate prices increases to their retail water customers resulting from higher power prices at the wholesale water level.

Finally, ARB's articulation of the reasons that wholesale water utilities are ineligible to receive free allowances (*i.e.* no direct end-use customer relationship and thus no price signal) is inconsistent with the rationale provided for the regulations that have been developed. POU retail electric providers will be permitted to retire their free allowances in order to meet their compliance obligations as importers or generators, resulting in no price signals at the retail level. Although the ARB apparently intends for the POUs to use the value of the free allowances to offset rate shock associated with rate increases, there is nothing in the statute that compels this result, and few public agencies will increase rates unless they are required to do so. Thus, not only has ARB created a price signal metric for measuring the need for free allowances that is not found in the statute, but it has also applied that metric in an arbitrary, inequitable manner. (MWDSC4)

Comment: Exempting Metropolitan from the list of "covered entities" is the best public policy option. After careful internal review and discussions, Metropolitan concluded that the cap-and-trade regulatory scheme developed by ARB is simply not viable or feasible for a public water supply agency. As ARB staff has recognized, Metropolitan does not provide electrical service to any load other than the CRA pumping plants and is therefore not an electric utility. However, contrary to the classification to which we have been assigned in the cap-and-trade regulations, Metropolitan is also not a marketer of electricity. To demonstrate our unique status in the California energy markets and support our argument for an exemption from the cap-and-trade regulations, Metropolitan asserted the following in our August 11th comments:

- Metropolitan is not a marketer of electricity, although it is classified as such under the Mandatory Reporting Regulation and Cap-and-Trade Program.
- Metropolitan does not purchase power for the purpose of resale.
- As a public agency, Metropolitan is legally required to pass all of its costs to ratepayers.
- Unlike retail electricity providers, including electric publicly-owned utilities, Metropolitan (based on ARB‟s decision) will receive no cost mitigation for its member agencies and ratepayers.
- As a public agency, Metropolitan should not be compelled to participate in the carbon market against for-profit market participants, including opt-in entities.
- Metropolitan's role, specifically the purchase of imported power to deliver water, is as a consumer of electricity, not a marketer, retail provider, or generator.
- The compliance obligation to acquire and surrender allowances will result in highly volatile costs to Metropolitan because of the variability of Metropolitan's energy imports for the CRA and the anticipated increase in the auction price of allowances. (For example, from 2005-2010 Metropolitan's historical imported electricity has ranged from 0 to 750,000 megawatt-hours.)
- The emissions assigned to Metropolitan's imported electricity are already below its 1990 levels when Metropolitan had an agreement for coal energy from the Navajo Power Plant.

In light of Metropolitan's clear differences with both electric utilities and for-profit marketers, Metropolitan urged the ARB to adopt specific language that would create a new reporting category and definition under the regulations. Under this proposal, Metropolitan would continue to report our imported electricity annually, would continue to maintain the required records and verifications, and would continue to pay the annual Cost of Implementation Fee for our imports. Metropolitan would also agree to certify that, if we alter our market behavior in a manner that would make us a true marketer of electricity, we would become subject to all of the requirements imposed upon covered entities. However, since Metropolitan would not be classified as an electricity marketer or an Electric Distribution Utility (EDU), we would not have a compliance obligation under the cap-and-trade program. (MWDSC4)

Comment: The development of a water sector-specific cap-and-trade compliance program and/or a deferral of the regulations for the water sector until such regulations are developed is appropriate. Metropolitan also proposed the creation of a compliance program to integrate water sector measures for energy efficiency and renewable energy projects, as specified in ARB‟s AB 32 Scoping Plan. This proposal is in fact consistent with the water sector measures that ARB proposed in the "Recommended Actions" section of the Scoping Plan for water. Metropolitan proposed to work with ARB along with other water agencies to develop the program and work towards implementation starting in 2014-2015. Deferring actual implementation of water sector regulations would allow ARB staff to concentrate priorities and resources on implementing the cap-and-trade program for the electric and industrial sector in 2012-2013 and would avoid imposing unnecessary and inequitable costs, potentially through duplicative regulations, on the water sector. To that end, Metropolitan proposed the following:

- Develop a compliance strategy or memorandum of understanding for Metropolitan as a consumer of wholesale electricity that integrates the imported energy issue into a comprehensive water sector program that includes measures identified in the AB 32 Scoping Plan, such as energy efficiency and renewable energy projects; and
- Defer Metropolitan/water sector measures until 2014 or 2015, after the cap-and-trade program is implemented. (MWDSC4)

Comment: The Initial Modifications, in Appendix A, focused exclusively on the alleged obstacles to providing free allowances to the water sector and did not address Metropolitan's exemption and deferral proposals. In our August 11th comments and in numerous meetings with ARB staffers, Metropolitan consistently and vigorously pressed the point that, as a public agency that provides water to much of Southern California, we should not be both treated as a for-profit marketer for purposes of regulation and denied the price mitigation provided to the public agencies that provide electricity to Southern Californians. Not only did ARB staff not provide Metropolitan with any of the revisions to the cap-and-trade regulations that we requested, it did not even address Metropolitan's arguments in the Second Modifications, notwithstanding the fact that the Second Modifications will likely be staff's final opportunity to address the comments of stakeholders prior to ARB‟s planned submission of the cap-and-trade regulations to the Office of Administrative Law (OAL) in October. (MWDSC4)

Comment: The proposed regulations are fundamentally inequitable to Metropolitan and our ratepayers. A consistent theme in the comments submitted by the wholesale water providers has been the inequity inherent in imposing increased costs on both electric and water customers, yet only providing offsetting price mitigation to electric customers. On page 16 of Appendix A to the Initial Modifications, ARB concluded that the publicly-owned water utilities are akin to electricity marketers, not distribution utilities, and that providing free allowances to the water agencies is inappropriate since the wholesale water utilities do not "maintain direct relationships" with their end-use customers and, thus, allocating allowances to these utilities might result in "the deterioration of the emissions price signals in the water sector. This analysis is notable for its flawed assumptions and the facts that it omits or concedes. ARB's analysis does not deny that end-use water customers, like end-use electric customers, will be impacted by cap-and-trade-related cost increases; it does not propose to protect water customers by providing price mitigation to retail water providers; and it does not explain why "price signals" are more important than equity.

ARB's decision to sacrifice equitable treatment of all stakeholders in order to promote the vague economic concept of price signals is indisputably inconsistent with what AB 32 requires. Section 38562(b) of the statute provides that, "to the extent feasible," ARB must "[d]esign the regulations, including the distribution of emissions allowances, in a manner that is equitable." As the court found in a case involving a public agency's elimination of medical services, Morris v. Williams, 67 Cal.2d 733, 757 (1967), the language "to the extent feasible" means that an administrative agency must use every "feasible" effort to accomplish the directive. The court concluded that an administrative agency's discretion in the rulemaking process is circumscribed by the express requirements on the statute and that "feasible, in short, means capable of being done." Id. Thus, ARB can develop regulations that promote price signals, but it does not have the discretion to elevate this goal above the equitable treatment of all entities. Since equitable treatment of all public agencies is feasible, it trumps ARB's price signal goal. Throughout the rulemaking process, ARB staff has expressed the concern that exempting Metropolitan from the coverage of the cap-and-trade regulations will create a gap in the regulations, since all emissions associated with imported energy will not be accounted for. In a conference call between Metropolitan and ARB staff, one ARB staffer indicated that exemptions would undermine the "purity" of the cap-and-trade program. ARB‟s concerns are unfounded. Section 38505(m) of AB 32 does specify that "statewide greenhouse gas emissions" include electricity that is either generated in state or imported. However, the statute does not require that all imported electricity be covered by a cap-and-trade program. The statute merely requires that all greenhouse gas emissions be reported and that these emission levels be reduced to 1990 levels by 2020. Section 38570 permits the ARB to include "market-based compliance measures" in the regulations, provided that the measures consider cumulative impacts, prevent increases in air pollutants, and maximize economic benefits. Ensuring that all emissions are captured within the market-based mechanism is not a requirement. Therefore, the ARB is not prohibited from exempting from cap-and-trade coverage emissions associated with an entity's imports, and it should do so where, as in this instance, including these emissions would result in inequitable treatment. (MWDSC4)

Comment: The proposed regulations will likely result in duplicative regulation of the water sector. ARB has consistently minimized the cost impact of the cap-and-trade regulations on the water sector; it is clear, however, that water customers will be burdened with significant overall cost increases as a result of the regulations. In our December 14, 2010 comments, Metropolitan estimated that the annual cost of purchasing allowances to cover our imported energy needs would be between $11 million and $22 million, depending on auction prices. The decision by ARB to neither exempt Metropolitan from the cap-and-trade regulations nor defer the applicability of those regulations raises the specter of even greater inequities. Specifically, Metropolitan, our customers, and other water agencies will be forced to bear the cost burden of cumulative regulations when the water sector-specific regulations are implemented.

In Section 17 of its Scoping Plan, ARB "recommends a public goods charge for funding investments in water management actions that improve water and energy efficiency and reduce GHG emissions." ARB anticipates that such a charge "could generate $100 million to $500 million." Given that energy efficiency measures will undoubtedly involve reducing GHGs associated with energy consumption, these measures will require Metropolitan to pay a significant amount of money for renewable energy at the same time that we are buying allowances for our imported energy. The likelihood of this additional cost burden is acknowledged in the Scoping Plan, which recommends a "mechanism to make allowances available in a cap-and-trade program" to, among others, "water suppliers," and concludes that an "allowance set-aside will be evaluated during the rulemaking for the cap-and-trade program." Other than the cursory, one-paragraph discussion in Appendix A to the Initial Modifications, no such evaluation has been done.

Similarly, the July 12, 2010 study "Implementing a Public Goods Charge for Water" (PGC Study), authored by three U.C. Berkeley economists on behalf of the Public Utilities Commission and the Water Energy Team of the Climate Action Team (WetCat), estimates that "approximately 20 percent of all electricity consumed in the state" is used for "water delivery, treatment, and use." (PGC Study at 5). The study characterizes the "[g]reenhouse gas emissions from pumping, treating, and heating water" as a "negative externality" that must be taxed in order to accomplish the goals of AB 32. Id. at 6. With respect to the ultimate cost to water consumers, the study concludes that a $680 million dollar per year public goods charge is necessary because, while publicly-owned water utilities have the ability to raise rates to fund GHG-reduction measures, "they are often reluctant to do so."

Thus, ARB's own Scoping Plan, as well as the study commissioned to implement it, have concluded that the water sector should be heavily taxed to fund GHG emissions-reducing measures. By determining in the cap-and-trade regulations that publicly-owned water utilities must incur costs to cover the emissions associated with moving water without providing any indication as to types and magnitude of additional costs that those utilities will incur as a result of to-be-developed water sector measures is grossly unfair. This is particularly true given the strong indications that Metropolitan will be required to mitigate emissions costs associated with our energy imports through both the cap-and-trade regulations and the water sector measures. (MWDSC4)

Comment: DWR refers to its prior comments, dated December 15, 2010, and August 11, 2011, and reminds the Board that the current version has not remedied the deficiencies related to the treatment of DWR as outlined in those comments.
As summarized in the December 15 comment letter:

Under AB 32, DWR's unique status as a state agency requires that it be exempt from this regulation. Alternatively, DWR should receive free allowances to mitigate for the impact on water ratepayers. AB 32 also requires that regulated parties be treated equitably and that early action receive appropriate credit. AB 32 requires the proposed regulation be cost-effective, and applying the regulation to DWR is not cost-effective. The proposed regulation results in a transfer of funds from water ratepayers to electricity ratepayers, which cannot be justified. The proposed regulation poses *undue financial risk to DWR. Environmental and economic impacts on DWR and water users were not addressed. Finally, the imposition or threat of a fourfold penalty on public agencies is unduly punitive and unnecessary to achieve compliance.*

The draft regulation presented to the Board in late 2010 reflected extensive discussions with many interests in the electricity sector—except DWR. The result was that DWR's interests and unique issues were not presented to ARB staff and thus not addressed in the draft regulation. In December, the Board directed staff to work with DWR to address its concerns. ARB and DWR staff did subsequently meet, at which time DWR twice presented proposals for the use of allowances. However, the ARB staff asserted that despite the invitation for public comment, strict adherence to the draft structure established for cap & trade was essential, and that DWR's proposals would upset that structure. Because of this stance, a full exploration of the treatment of DWR and its proposals did not occur.

Clearly there are a number of instances in which the draft regulation has been changed to accommodate unique issues and deviate from painstaking adherence to cap and trade's underlining economic theory. It is thus disingenuous to suggest that similar accommodations could not be made for DWR. In fact, equity demands that such accommodations must be made; specifically, DWR should receive allowances similar to the POUs and re-open discussions with ARB staff on the appropriate use of allowance proceeds.

Therefore, DWR requests the Board to direct staff to identity a method for incorporating equitable mitigation of the impact cap and trade will have on DWR as the operator of the State Water Project. As a single entity with unique issues relative to other regulated parties and moreover as a fellow state agency and member of the Governors Climate Action Team it is appropriate to address these issues in a memorandum of understanding rather than in regulation. (DWR3)

> **Response:** We do not agree that DWR, SWP, or MWD should receive an allocation of free allowances. Some water purveyors also sell electricity into the CAISO market. The GHG emissions compliance costs must be passed through to end-users. If we allocated allowances to these water purveyors and then they offered their surplus electricity without an appropriate carbon price into the CAISO market, the dispatch order in the CAISO market could be distorted, eventually leading to greater GHG emissions. To avoid this perverse outcome, we believe it is important that these entities, as even an occasional seller of electricity into the CAISO market, be subject to an equitable cost of carbon.
>
> The purpose of allowance allocation to the electric utilities is not for price mitigation, but to provide ratepayer relief while maintaining the price signal. We believe that DWR, MWD, and the SWCs are able to pass the cost of compliance down to the entities they serve, which in turn will pass the cost of carbon on down to the end-user, or final consumer of water. EDUs are allocated

allowances for the benefit of ratepayers, and we expect the EDUs to pass through the cost of GHG emission compliance obligations to their ratepayers.

Because Metropolitan, DWR, and the SWC are not providers of water services to end-use customers, we directed the allowances associated with their electricity usage to electric utilities, IOUs, and POUs, which do have relationships with end-use customers that allow them to return value in a manner that does not distort the incentives created by the cap-and-trade regulation. Some of the POUs also serve end-use water customers. In this way, we balance equity and efficiency by providing transition assistance for water customers while maintaining the integrity of the cap-and-trade program.

Regulation of the water sector through the cap-and-trade program is not duplicative. All major sectors covered by the program, including water, are now, or may in the future be, subject to complementary policies aimed at bringing about long-term change and GHG emissions reductions. The cap-and-trade program provides additional incentives to achieve the reductions already targeted by individual sectors, as well as other cost-effective reduction strategies that may not be targeted. In this way, the cap-and-trade program can be a cost-effective overlay to any preexisting policy.

We also do not agree the water purveyors should be exempt from the program. As DWR notes, AB 32 directs us to include emissions from imported electricity used to serve California end users and to take into account the relative contribution of each source. DWR is a covered entity because DWR imports electricity. DWR's compliance obligation is equivalent to the obligation for electricity importers. Likewise, MWD imports electricity and is similarly covered by the regulation. We believe this treatment best ensures the integrity of the cap.

Furthermore, in Resolution 11-32, the Board directed the Executive Officer to continue discussions with stakeholders to identify and propose, as necessary, during the initial implementation of the cap-and-trade program, potential amendments to the regulation, including distribution of allowance value associated with cap-and-trade compliance costs from using electricity to supply water and the expected ability of allowance allocation and other measures to adequately address the incidence of these costs equitably across regions of the State.

J. ENFORCEMENT

Penalties

J-1. Comment: In section 96014, the Second 15-Day Revisions properly recognize that “daily” penalties are excessive, and that separate violations should accrue every 45 days for compliance instruments that remain unsurrendered, rather than on a daily basis. NCPA urges CARB to further address the issue of potentially excessive penalties and, when looking at violations under this section, consider each 1,000 compliance instruments (or portion thereof) as a single violation, rather than one compliance instrument. Given the order of magnitude of allowances in the Cap-and-Trade Program, violations based on each 1,000 instruments is a viable option that still holds compliance entities accountable, without being excessive. (NCPA4)

> **Response:** We did not bundle the allowances into 1,000 allowance units for purposes of determining penalties. One metric ton of CO_2e is the basic unit for both reporting under the MRR and for compliance or trading under the cap-and-trade regulation. It is therefore an appropriate unit by which to count violations under both rules. Moreover, Health and Safety Code section 38580(b)(3) authorizes ARB to define penalties on a per-unit basis, proportional to the conduct, rather than defining violations purely in terms of days. The penalty structure has also been revised to provide that, rather than having penalties for unsurrendered allowances accrue daily, penalties accrue every 45 days. This provides flexibility to the compliance entity to obtain additional allowances, either through an auction or purchase of allowances through the allowance price containment reserve, and also reduces the potential liability for compliance entities.

J-2. Comment: The Utilities support the change in section 96014(b) that “A separate violation accrues every 45 days after the end of the Untimely Surrender Period for each required compliance instrument that has not been surrendered.” (MID4)

> **Response:** We thank the commenter for its support.

J-3. Comment: The removal of allowances in order to satisfy a penalty in a quantity that exceeds actual emissions penalizes all market participants, not just the entity in violation of the regulation. The penalty portion of an enforcement action should be either direct monetary payment or an “in kind” payment. (NEXTERAENERGY3)

> **Response:** We believe that commenter refers to the excess compliance obligation provision of the regulation. This is not a penalty. Nevertheless, we note that the regulation does not remove the additional allowances permanently from the market. It places the additional surrender obligation allowances back in the auction account, making those allowances still part of the market. The additional surrender obligation is an additional deterrent to noncompliance.

J-4. Comment: We ask that ARB reconsider its proposed modification to section 96014(b) to calculate violations every 45 days rather than daily. We find the proposal needlessly curtails ARB's ability to ensure penalty amounts are sufficient to deter non-compliance. On the surface, calculating violations daily allows for large penalty amounts to accrue, but the concern that this will result in gross and excessive penalty amounts belies other requirements in the Health and Safety code and decades of ARB's experience in enforcing regulatory programs under those provisions. Calculating violations daily is the standard approach to assess penalties under the Health and Safety Code, which are the penalty provisions applicable to violations of the cap-and-trade rule. Before imposing any penalty amount, ARB is required to consider all relevant circumstances for each violation, including a set of criteria that weighs heavily against levying an excessive penalty for failure to meet an untimely compliance obligation. However, the additional leeway afforded by daily calculation of violations would afford ARB greater ability to tailor penalty amounts in proportion to the nature and extent of the violation. Given ARB's extensive experience in enforcing regulatory programs under these provisions, we do not find credible assertions that the cap-and-trade rule warrants special treatment through periodic rather than daily calculation of penalties. The success of the cap-and-trade program is contingent on ARB ensuring market participants play by the rules. To ensure fair play, it is incumbent on ARB to retain the full range and extent of enforcement tools at its disposal. (KUSTIN19)

> **Response:** We instituted the change in response to analysis and stakeholder comments that demonstrated that leaving the "per ton-per day" calculation in place would result in penalties that may be disproportionate to the violation. ARB fully intends to enforce its regulations and ensure that market participants "play by the rules." We believe that the penalties in place in the final regulation balance these interests appropriately. See also responses to Comments J-15, J-20, J-23, J-25, and J-33 in the 45-day responses.

Conflict Resolution

J-5. (multiple comments)
Comment: Currently the cap-and-trade and mandatory reporting regulations give CARB's Executive Officer sole authority on program implementation, including determining whether regulated parties have complied with regulations and to determine penalties. Absent costly and time consuming litigation, there is currently no independent administrative option for stationary source facilities to challenge the Executive Officer's decisions that could not be resolved. The AB 32 IG believes the Executive Officer should not have the final decision on such a comprehensive program as AB 32, and instead it would be in both CARB's and the regulated industry's best interest that a formal, autonomous dispute resolution process should be established in order to provide independent decision making with equity for all parties involved in any dispute. This program should use an unbiased mechanism to resolve disputes, variances and penalty disagreements with the Executive Officer. Without such a program issues that could be resolved relatively quickly could become time-consuming litigation which could hinder the goals of AB 32. (AB32IG3)

Comment: CalChamber supports the adoption of a formal autonomous dispute resolution process that would enable facilities to challenge and resolve disagreements prior to potential enforcement actions through an equal process for all parties involved in any dispute. (CALCHAMBER4)

Comment: Currently, the ARB Executive Officer and staff make significant enforcement decisions that are not subject to review. The only appeal process available to a regulated party is to sue the State. The AB 32 program requires that the ARB create a brand new, far reaching, and complex program under very tight statutory deadlines. The statutory deadlines are driving rapid development of regulations, which may have unintended consequences and unknowable problems at every individual facility. Since every facility is different these types of problems, which bridge both energy and air pollution issues, CCEEB recommends that ARB establish an independent administrative dispute resolution process that will provide a fair, efficient, and predictable process available to all individual facilities. This will reduce the money and time spent defending lawsuits and in informal negotiations. It will also increase the transparency of the appeal process as all interested stakeholders can weigh-in during a hearing. The proposed dispute resolution process could be modeled after existing air pollution hearing processes for disputes at individual facilities that occur under local air district rules. (CCEEB4)

Comment: Currently the cap-and-trade and mandatory reporting regulations give CARB's Executive Officer sole authority on program implementation, including determining whether regulated parties have complied with regulations and to determine penalties. Absent costly and time consuming litigation, there is currently no independent administrative option for stationary source facilities to challenge the Executive Officer's decisions that could not be resolved. CLFP believes the Executive Officer should not have the final decision on such a comprehensive program as AB 32, and instead it would be in both CARB's and the regulated industry's best interest that a formal, autonomous dispute resolution process should be established in order to provide independent decision making with equity for all parties involved in any dispute. This program should use an unbiased mechanism to resolve disputes, variances and penalty disagreements with the Executive Officer. Without such a program issues that could be resolved relatively quickly could become time-consuming litigation which could hinder the goals of AB 32. (CALFP4)

> **Response:** The Executive Officer does not unilaterally "set" penalties. Health and Safety Code section 38580 provides ARB with enforcement authority over AB 32 regulations, including the authority to define the violations. This authority does not extend to assessing, imposing, or determining final penalty amounts. The governing statutes allow ARB to *seek* penalties in an administrative or judicial proceeding. In many of its enforcement actions, ARB and the entity from whom ARB is seeking penalties will reach a mutual settlement agreement, including an agreed-upon penalty amount. ARB may seek penalties in an administrative or judicial action, in which the ultimate penalty

amount is determined by a neutral judge, based on the statutory penalty structure. In no instance is ARB or its Executive Officer able to unilaterally assign a penalty amount on a violator. Additionally, ARB notes that the creation of a dispute resolution process is outside and beyond the scope of these regulatory amendments. Notwithstanding this, ARB disagrees with the underlying premise of the commenter's suggestion; namely that there is no fair, independent, autonomous method of resolving these disputes. As the commenter acknowledges, the existing recourse is to challenge a decision in court. That process is well established and understood by regulated entities, the public, and ARB. Inventing a new, additional dispute resolution process, whether that would be through the creation of a hearing board or an administrative hearing, will not necessarily reduce the time or expense of resolving such disputes. In fact, and contrary to the claimed rationale of the commenter, ARB believes such additional process may actually increase the time and expense of resolving these matters, since parties could still ultimately end up back in court. Including an additional dispute resolution process would give rise to delay that could have broad market impacts given the timelines in the cap-and-trade regulation. As such, ARB does not agree that including such a process would be appropriate.

Regarding variances, ARB does not believe the "variance" process used by the air districts is necessary for the MRR or cap-and-trade regulations and believes that it could disrupt the market features of the cap-and-trade regulation, which relies on the emissions data reports from the MRR. Unlike the future emissions addressed by air district variance processes, the emissions at issue in the MRR and cap-and-trade regulation have already occurred and been reported to ARB. As such, no "variance" is required; therefore, the formal variance process used by the air districts would be inappropriate for the MRR. In addition, instead of a formal variance process, the MRR includes a process by which a facility may petition for an interim data collection method under certain circumstances that result in data loss due to unforeseen reasons. The MRR also contains a dispute-resolution process for when a reporting entity and its verifier do not agree on the quality of the emissions data report. We believe that these two design features will ensure an efficient market process where timely data are critical to the functioning of a well-developed market program and that they will address the commenter's concerns.

See also response to Comment J-37 in the 45-day responses.

Violations

J-6. Comment: The recently proposed enforcement provisions that consider failure to report every ton of excess emissions and submittal of inaccurate information as separate violations would potentially result in unwarranted and excessive penalties, relative to other criteria pollutant penalties. GHG emissions levels are a thousand times higher than criteria pollutant levels. The mandatory reporting rule is complex, and the volume of data collected is enormous; the sheer size and complexity significantly increases the potential for unintended reporting errors. In addition, the proposed enforcement language would still permit ARB to impose penalties for the period between submission of the initial unverified repot and the final verified emissions repot if the verified report indicates inaccuracies in the initial report. ARB should further amend this section so that changes in reported emissions occurring between the initial emissions data report and submission of the final verified emissions data report are violations only if initial under-reporting was due to intentional misrepresentation. (CCEEB4)

Response: This comment addresses the Mandatory Reporting Regulation provisions. No response is required.

J-7. Comment: In section 96014, the provision was deleted that stated each day of violation is a separate offense under subpart (b). The new language specifies that a separate violation accrues every 45 days for an untimely surrender. This is a substantial reduction in the number of days for each violation and results in a dramatic reduction in the potential civil penalty available by statute. We strongly recommend reinstating the previous language which clearly establishes daily violations for each day of the compliance period. (SCAQMD5)

Response: See response to Comment J-4, above.

J-8. Comment: We recommend reinstating section 96014(c). The Health and Safety Code is based on actual days of violation, so this provision is of critical importance. If an enforcement action is taken to court, the extent to which actual days of violation can be established will be persuasive to a judge. Accordingly, in order to ensure adequate deterrent value in cases which may be based on negligent or intentional conduct, we recommend that the rule provide that a separate day of violation is established for each day of the applicable compliance period unless the program participant can establish compliance for each of those days. The violations continue until final compliance is achieved. This will provide an adequate number of days of violation to deter future misconduct at the facility and throughout the regulated community. We recognize that AB 32 allows CARB to develop a method of converting a violation of any rule adopted under AB 32 into "days of violation" (Health and Safety Code section 38580(b)(3)), but we believe it is important to maintain the ability to seek a penalty for each day of violation. (SCAQMD5)

Response: See response to Comment J-4, above.

Miscellaneous

J-9. Comment: Many of the proposed amendments made within the second 15 day changes make this a stronger more enforceable regulation. Changes made within section 95921(g) requiring holders of clearing accounts to maintain transaction records for ten years and to provide transaction records within ten days of a request by the Executive Officer are helpful with transparency and related enforcement. (SCAQMD5)

Response: We thank the commenter for its support.

K. LEGAL

Public Process

K-1. Comment: The development of the cap-and-trade regulations did not occur through an open process. Metropolitan has provided comments to the Board in response to every iteration of the cap-and-trade regulations articulating most of the concerns that Metropolitan is still expressing today. Staff stated at the December 2010 Board meeting adopting the cap-and-trade regulations that, with respect to the wholesale water utilities, ARB staff had “missed an important category of customers” and indicated a willingness to talk to wholesale water agencies. Metropolitan began meeting with ARB staff following the Board adoption of the regulations and has since met with them several times to discuss Metropolitan’s concerns and to advocate specific proposals for addressing those concerns. At some of these meetings, ARB staff indicated that they were reluctant to make changes to the regulations that would be unpalatable to the EDUs, including publicly-owned utilities, investor owned utilities, and the Joint Utilities Group (JUG). Ultimately, ARB staff did not adopt any of the recommendations made by Metropolitan. Metropolitan is very concerned that, in working directly with the JUG to craft price mitigation measures for their members, ARB staff may have impermissibly made decisions without engaging non-JUG members. The Public Meetings Act, as contained in section 11120 of the Administrative Procedure Act (APA), provides that it is the intent of that law “that actions of state agencies be taken openly and that their deliberation be conducted openly.” AB 32 itself reinforces this directive by requiring that the ARB “adopt rules and regulations in an open public process.” The sequence of events leading to ARB’s determination that free allowances would only be given to Local Distribution Companies (LDC) gives rise to the concern that stakeholders such as Metropolitan did not have an adequate opportunity to advocate their positions prior to a de facto decision made by ARB staff. Following the issuance of a recommendation by the ARB’s Economic and Allocation Advisory Committee on January 2, 2010, the JUG, representing all of the major LDCs in California, began meeting with ARB staff on a regular basis to discuss the allocation of free allowances. According to information made available to Metropolitan, the JUG met with ARB staff on numerous occasions prior to the release of the draft cap-and-trade regulations in October of 2010. In a February 11, 2010 meeting, held seven days prior to the public Ad Hoc Committee meeting to discuss allowance allocation, the JUG provided ARB staff with a recommendation that largely tracks the draft cap-and-trade regulations with respect to free allowances. At an August 16, 2010 meeting, staff indicated that they were hopeful that they could build on the agreement reached by the utilities. In advance of the spring 2011 workshops at which allowance allocation was publicly discussed, Metropolitan received information from a member agency indicating that ARB planned to meet with a subgroup of utilities prior to the public meetings to discuss allowance allocation. One consequence of the failure to include the water sector in this process is that allowances associated with the emissions of the wholesale water utilities were allocated to other entities. ARB has in fact acknowledged this inequity in Appendix A to the Initial Modifications, where, in reference to the water utilities, it states that “each of these entities use electricity to transport water into and around California, and the emissions associated with this activity are included in the pool of allowances set aside for the electric sector." This strongly suggests that the EDUs who participated in the emissions allocations discussions obtained not only the free allowances associated with their own electricity usage, but also a pro rata share of the allowances associated with the electricity use of the water utilities. Metropolitan does not raise the issue of transparency in order to cast aspersions on either ARB staff or JUG members. Metropolitan assumes that the representatives from ARB and the JUG were attempting to resolve issues pertinent to the retail electric utilities in a time-constrained environment in advance of the October 2010 issuance of the proposed cap-and-trade regulations. However, an unintended consequence of these closed meetings was that stakeholders, such as Metropolitan, which were not included in meeting announcements, were unable to voice their concerns and assert their interests in a process that led to the formulation of regulations with a profound impact on many entities outside of the JUG. While staff and the Board made the ultimate decision with respect to the regulations, they did so without the input of many affected parties. (MWDSC4)

> **Response:** ARB has complied with all provisions of the Administrative Procedure Act. The commenter admits that ARB met with the commenter on multiple occasions during the pendency of the rulemaking, including receiving comments from the commenter on numerous occasions that were not limited to the comment periods required by Government Code sections 11346.8. The commenter claims in submitted comments that it is not an electrical distribution utility. ARB agrees with this assertion. As such, it would not have made sense for ARB to include the commenter in discussions with electrical distribution utilities. ARB always meets with a variety of groups with similar interests, including refineries, electrical distribution utilities, and environmental groups. The groups representing the water interests chose to meet with ARB separately on multiple occasions. ARB cannot require that groups with common interests work together. ARB held multiple public workshops, both before and after the start of the official rulemaking process required by the APA. The commenter submitted comments and those comments are answered elsewhere in this document. ARB disagreed with the commenter's concerns and solutions, and ARB has explained in response to those comments the reasoning behind not accepting those suggestions. ARB included language in the resolution adopted on October 20, 2011, to continue analyzing the issues presented by the commenter and report back to the Board at a later time about the progress and results.

K-2. Comment: Contrary to the requirements of the APA, ARB did not respond to Metropolitan's comments. In addition to requiring open meetings, the APA requires that public agencies be responsive to public input. As the court articulated in Morning Star Co. v. State Board of Equalization, 38 Cal.4th 324, 333 (2006) (citing Gov. Code section 11346), "[i]f a rule constitutes a „regulation‟ within the meaning of the APA it may not be adopted, amended, or repealed except in conformity with, basic procedural requirements ‟that are exacting." The court notes that one of those exacting requirements is that the public agency must "respond in writing to public comments," and cautions that "[a]ny regulation or order of repeal that substantially fails to comply with these requirements may be judicially declared invalid." Save for the one-paragraph discussion in Appendix A to the Initial Modifications regarding the propriety of allocating free allowances to water utilities, the ARB has not addressed the arguments repeatedly proffered by Metropolitan with respect to cap-and-trade. Although, as discussed below, allocating free allowances to wholesale water utilities provides a bare minimum of protection for water customers against rising costs, Metropolitan's primary arguments regarding exemption and deferral have been completely ignored in the numerous iterations of the cap-and-trade regulations that the ARB has released in the last year. While the AB 32 implementation proceedings are governed by the APA, ARB's blatant disregard for public input and administrative dictates in its development of the cap-and-trade regulations is highly analogous to ARB's violation of CEQA in its approval of the Scoping Plan, as found by a court in Association of Irritated Residents v. ARB, Statement of Decision, Case No. CPF-09-509562, Superior Court of California, County of San Francisco (March 18, 2011). There, as here, the ARB failed to adequately respond to public comments prior to making a determination. ARB's repeated failure to address Metropolitan's comments on the cap-and-trade regulations makes it susceptible to the same type of legal challenge. (MWDSC4)

> **Response:** ARB has fully complied with the Administrative Procedure Act throughout the course of this rulemaking. The Administrative Procedure Act requires an agency to respond to all comments in the Final Statement of Reasons, which is typically made available at the end of the rulemaking process. Government Code section 11346.9(a)(3) requires the Final Statement of Reasons to include the comments and the agency's response to the comments, and to identify changes made in response to comments or explain the reasoning behind rejecting suggested changes. The commenter appears to believe that because ARB did not implement the changes suggested by the commenter, that they were disregarded. The APA does not require that comments be responded to prior to a decision, only that they be considered. The Board considered these comments prior to its adoption of the regulation on October 20, 2011. ARB also disputes that its previous approval of the Scoping Plan violated CEQA. See response to Comment K-25 in the 45-day responses.

Federal Agencies

K-3. (multiple comments)
Comment: DoD commitments to reduce greenhouse gas (GHG) emissions will accomplish much greater reductions while maintaining military flexibility to accomplish those reductions without threatening National Security. The charges for participating in the cap-and-trade program constitute a tax on the federal treasury. It is impermissible to obligate federal funds to pay state taxes. Therefore, no DoD comptroller may allow the purchase of allowances or compliance certificates with federal dollars. The cap-and-trade regulation has the perception of discriminating against the military and the federal government because it does not apply to federal entities "in the same manner and to the same extent" as other nongovernmental entities. As such, it does not fit

within the conditional waiver of sovereign immunity in the Clean Air Act (CAA). (USDOD3)

Comment: Is the allowance charge an approximation for the benefits received by the government facility? No, the charge is derived from the per capita allowance for the right to emit GHGs. Moreover, the sale of allowances at auction will necessarily generate revenues that exceed the costs of the program and have already been proposed by the California legislature to be set aside for community benefit funds. (USDOD3)

Comment: Is the allowance charge structured to produce revenues that will not exceed the total costs to the government of the benefits to be provided? No, the charge for the right to emit GHGs is designed to produce revenue that may be appropriated later by the State of California for purposes to be determined after the revenues from the auction are received. The Resolution 10-42 specifically describes returning allowances to disadvantaged households and legislation like SB 535 and AB 1405 demonstrate the State of California's intent to leverage funds generated under the cap-and-trade program against costs outside of the program itself. (USDOD3)

Comment: Is the program is implemented in a non-discriminatory manner? No, the program has the practical effect of discriminating against Federal agencies because it does not allow for full participation of Federal agencies given their contracting and appropriation constraints under the Antideficiency Act and implementing regulations. The GHG allowance allocation portion of this program has been significantly influenced by the goal to eliminate economic risk, and as a result is outside the CAA section 118 waiver of sovereign immunity, which only allows state authority over Federal agencies for the control and abatement of air pollution. (USDOD3)

Comment: Do some aspects of the allowance allocation scheme directly discriminate against federal agencies? Yes. As illustrated in Figure J-5 (p. J-20) and Table J-7 (p. J-32), in the On-site Fuel Combustion and Process Emissions category and the Heat Purchased, Electricity Purchased, or Combined Heat and Power (CHP or COGEN) produced on-site category, federal facilities that become a "covered entity" must purchase all allowances required to cover their GHG emissions from on-site fuel combustion to comply with the program. Yet under Table 8-1 industrial facilities will receive free allocations of allowances to cover their benchmarked direct costs for GHG emissions from these source categories. (USDOD3)

Comment: The CAA's Federal Facilities section 118, which conditionally waives sovereign immunity, authorizes the payment of reasonable regulatory fees in support of air pollution abatement program. According to the text of the statute, "[T]he Federal Government [shall] be subject to any requirement to pay a fee or charge imposed by any State or local agency to defray the costs of its air pollution regulatory program." There are many aspects of the cap-and-trade program, but the heart of the program is a trading of emissions allowances. This trading will generate revenues for both the State of California and for some covered entities. These revenues will bear no relationship to the costs of the regulatory program. These excess costs are the signature feature of the program that renders its costs as taxes rather than reasonable regulatory fees. Under the Supremacy Clause, the United States and its instrumentalities are immune from direct taxation by state and local governments. Appropriated funds are not available to pay tax assessments without a specific act of Congress waiving sovereign immunity. (USDOD3)

Comment: Military Comptrollers are required to follow all binding legal opinions, as well as those rendered by the DOJ and the GAO. Put plainly, Congress has not authorized the use of appropriated funds to participate in a market-based commodity exchange of pollution permissions where the generated revenues do not exclusively support the air pollution control program. Congress has authorized federal agencies to pay fees commensurate with the services performed for and benefits accrued to the federal pollution programs. Auction sales do not meet that definition. (USDOD3)

Comment: Under section 118(a) of the CAA, Federal agencies are only subject to state requirements and authority "respecting the control and abatement of air pollution in the same manner, and to the same extent as any nongovernmental entity." The California cap-and-trade program discriminates against Federal facilities. The program does not impose air pollution control and abatement requirements on Federal facilities in the same manner and to the same extent, because certain industrial facilities and distribution utilities operating the same type of emission units will be regulated differently. (USDOD3)

Response: The response to Comment K-8 in Chapter III generally describes the waiver of sovereign immunity contained in section 118 of the Clean Air Act (CAA), and why ARB believes this provision applies to federal agencies and departments (like the Department of Defense (DOD)) that are subject to the cap-and-trade regulation.

DOD claims that "the charges for participating in the cap-and-trade program constitute a tax on the federal treasury" that is not within the scope of the section 118 waiver provision. In support of this contention, DOD offers a number of arguments that can be distilled down to one: that although section 118 of the CAA waives sovereign immunity for the payment of reasonable regulatory fees to defray the costs of California's air pollution program, the costs imposed by the cap-and-trade program are an impermissible tax because the revenues generated bear no relationship to the cost of the program or the services provided to federal facilities, and the revenues will be spent for the general public benefit instead of controlling greenhouse gas (GHG) emissions.

DOD uses the three-part test applied by the Supreme Court in the 1978 case of *Massachusetts v. United States* (1978) 435 U.S. 444 to reach the conclusion that the charges for allowances constitute an illegal tax. However, it is not certain that the courts would apply the three-part test set forth in *Massachusetts*. It can be argued that a challenge to the cap-and-trade regulation by a federal agency must be brought in state court, and California law regarding taxes and fees would apply instead of federal law (see *South Coast Air Quality Management District (SAQMD) v. United States,* (C.D. Cal. 1990) 748 F. Supp. 732, 1990, in which a federal District Court refused to apply the three-part *Massachusetts* test because the court found that section 118 provides a complete waiver of sovereign immunity).

If one assumes that the three-part *Massachusetts* test does apply, however, we believe that the cap-and-trade program does not impose a tax under this test. First of all, DOD's analysis assumes that the revenues that will be generated by the cap-and-trade program will be appropriated by the Legislature in such a way that they would be a tax under the Massachusetts test. This is speculation, because no revenues have yet been collected by ARB or appropriated by the Legislature, and no decision has yet been made by the Legislature regarding how the revenues will be appropriated once they are collected.

In addition, DOD's analysis does not accurately characterize the many federal court decisions that have interpreted the *Massachusetts* test. DOD's analysis implies that a monetary charge paid by federal facilities is a "tax" except in very limited situations, such as where a state is charging for a specific service provided to a fee payer, or attempting to cover the administrative costs of running a regulatory program. Case law is not so limited. To give just one example, In *New York State Department of Environmental Conservation v. U.S. Department of Energy* (N.D., New York 1991) 772 F. Supp. 91), a federal district court affirmed state action to recover environmental regulatory fees owed to it by federal facilities. The Court noted that the charges imposed varied in relation to the size or quantity of each facility's operations (e.g., gallons, pounds, vehicles) rather than upon the particular services provided by the New York Department of Environmental Conservation (NYDEC). The Department of Energy (DOE) claimed that the fees sought were impermissible taxes and that they were unreasonable in light of the services provided by the NYDEC to their facilities. The Court examined the charges in light of the *Massachusetts* test. With regard to DOE's assertion that the charges failed the second prong of the test because they were based upon the size or quantity of an entity's operations rather than upon the actual services provided, and because NYDEC failed to correlate the charges assessed against specific federal facilities to the cost of services rendered, the Court agreed with the State "that the United States has misinterpreted and incorrectly applied the second portion of this test" because

> "the relevant inquiry is not whether the charges assessed by a state exceed the <u>specific services</u> rendered to a facility by the government. Rather, this prong relates to the <u>overall</u> benefits a facility receives from the government's services. In fact, the Supreme Court voted that this portion of the test is not failed even when a particular entity receives no specific services from the government at all." (emphasis added)

In the cap-and-trade program, the money expended to purchase allowances by DOD and private participants could be characterized as the payment of fees for the right to emit GHGs into the atmosphere. Contrary to the DOD's claim that the "cap and trade program creates a personal property interest in the right to emit a GHG allowance and then confiscates the property interest by requiring the possessor of the allowance to surrender the interest to the State of California for the general health and welfare," there exists no property interest and no vested right to pollute. No "right" of DOD is confiscated.

Finally, DOD claims that the cap-and-trade program discriminates against federal facilities, and therefore does not fall within the waiver of sovereign immunity provided in section 118 of the Clean Air Act, because certain industrial facilities operating the same types of emission units (such as cogeneration) may receive free allocation of compliance allowances, while federal facilities must purchase all of their allowances. We do not agree that the program discriminates against federal facilities, because federal facilities will be evaluated based on the same criteria as any other facility in California. However, as directed in Board Resolution 11-32, we will continue to work with the Department of Defense to ensure that appropriate GHG reductions are achieved by DOD.

Use Of Auction Proceeds

K-4. Comment: CARB has estimated the sale of allowance proceeds to be about $500 million in the first compliance period and up to $2 billion in the second and third compliance periods. CalChamber has long maintained that CARB's proposal to raise funds via an auction for reasons outside of administrative fee purposes is beyond CARB's regulatory authority. And throughout the regulation process, CARB has publicly identified possible revenue uses from the sale of allowances, even directing CARB's Executive Officer to deposit a percentage of annual proceeds to fund programs that 'reduce GHG emissions or mitigate direct health impacts of climate change, and promote green collar employment opportunities in the most impacted and disadvantaged communities in California...'. We caution CARB that these and other spending proposals are clearly outside the scope of administrative or regulation-related fees. CARB must keep in mind the State Constitutional requirement that fees must provide either a direct benefit or service to the fee payer, or be directly connected to a reasonable regulatory program serving the fee payers, otherwise, these fees are actually taxes and must be approved by a two-thirds vote of the legislature. Without a legitimate nexus, the above mentioned auction revenue proposals will likely be challenged since they are not only contrary to the legislative intent of AB 32 but are contrary to the procedural requirements of the State Constitution. (CALCHAMBER4)

Response: We believe that AB 32 provides ARB with the authority to conduct an auction as part of a cap-and-trade program. AB 32 authorizes ARB to "adopt a regulation that establishes a system of market-based declining annual aggregate emission limits for sources or categories of sources that emit greenhouse gas emissions" (Health and Safety Code section 38562(c); see also section 38570, which specifies additional criteria for market-based compliance mechanisms). These statutory provisions authorize ARB to adopt a cap-and-trade regulation and, in order to initiate a cap-and-trade program, emission allowances must somehow be allocated to participating sources. Thus, AB 32 directs ARB to “Design the regulations, including distribution of emissions allowances where appropriate, in a manner that is equitable, seeks to minimize costs and maximize the total benefits to California and encourages early action to reduce greenhouse gas emissions.” (Health and Safety Code section 38562(b)(1); emphasis added.)

There are a variety of ways to allocate allowances; they can be distributed free of charge, they can be sold at a predetermined price, they can be auctioned off with competitive bidding, or some other allocation method can be developed. AB 32 does not direct ARB to use any particular method to distribute allowances, and does not specify that some methods are allowed and others are not. Each method of distribution has pros and cons, and different methods will vary in their ability to meet the statutory criteria set forth in AB 32. Auctioning of allowances is one widely recognized method to distribute allowances, and is in fact the method that has been recommended by the Market Advisory Committee and many other economists. We believe that in authorizing ARB to distribute allowances, and requiring that market-based compliance mechanisms must meet certain criteria, the Legislature did not intend to forbid ARB from choosing this widely recognized distribution method. In other words, as the administrating agency charged with interpreting AB 32, ARB believes that AB 32 provides ARB with the authority to include auctions as a feature of a cap-and-trade program.

L. MARKETS

Trading, Market Conduct and Oversight

L-1. Comment: Throughout the rulemaking process, Evolution Markets has commented on provisions contained within section 95921 on "Conduct of Trade". We believe elements of this section provide an important foundation for California's carbon trading market. The market exists to offer entities the flexibility to find the lowest cost means of compliance with ambitious greenhouse gas reduction targets. Should rules governing trading activity unnecessarily constrain transactions or provide insufficient oversight, the market cannot effectively provide this important function. ARB correctly understands that the carbon market is likely to evolve to include a variety of transaction structures that allow entities to manage risk and achieve low-cost compliance. Provisions in section 95921 also allow the ARB Executive Officer to review requests for transfers to ensure they meet basic criteria for reporting and adherence to holding limit regulations. As an important proposed change, ARB suggests building in a "cure period" that offers an element of flexibility. Deficient transfer requests will be given three days to resubmit the request before transfers are executed. Transfer requests that are deemed deficient after transfer occurs will be given five days to resubmit the request, or the transfer will be reversed. Previously, ARB only had the authority to reverse trades, which would have forced entities to automatically unwind trades in the event of a deficiency. (EVMKTS3)

> **Response:** No response is required.

L-2. Comment: GreenX provided comments explaining how the Executive Officer's authority to reverse trades is extremely problematic and will have a disruptive effect on the market. In particular, the provision, as described in section 95920(b)(4), will interfere with the sanctity of contract, result in litigation between market participants, and will cause a lack of confidence in the secondary market for compliance instruments. (GREENX2)

> **Response:** We disagree with the comment. Section 95920(b)(4) states that the process for dealing with rule violations follows section 95921(b). In all cases when a deficient transfer request is detected, the parties to the underlying transaction will have the opportunity to correct the deficiency. In some cases the correction may involve resubmitting the corrected transfer request or submission of entirely new requests that solve the rule violation. A recorded transfer would only be reversed if the parties to the underlying transaction refuse to correct the deficiency.

(multiple comments)
L-3. Comment: While the "cure period" is a noted improvement, Evolution Markets still has strong concerns with the ability of the Executive Officer to reverse a transfer of compliance instruments. Reversing commercial transactions between counterparties creates a host of contractual and compliance issues. The foundation of a properly

functioning market is that commercial contracts between counterparties cannot be unwound. An obligation to sell allowances to another counterparty must be met, and once the transfer of allowances and cash has taken place counterparties cannot be expected to reverse this transaction. To create the possibility of a transaction reversal would introduce an unacceptable measure of risk to carbon transactions. Furthermore, such reversals may create a daisy chain of violations of holding limit provisions. In the instance of ARB reversing a transaction, the buyer of allowances will return the allowances to the seller. The seller may have sold the allowances to ensure it did not violate its own holding limits, and the return of allowances from the reversed transaction might then put the seller over its holding limit. This would, in turn, generate another series of reversals which would impact still other counterparties.

Lastly, ARB's transfer reversal authority could result in opportunities for market participants to game the cap-and-trade system. Entities that have either filed a deficient transfer request or have surpassed their holding limit may well welcome the ability of ARB to reverse a transfer, particularly if the trade underlying the transfer is out of the money at that given time. Therefore, Evolution Markets supports the introduction of a "cure period" and believes the proposed three or five day period is sufficient. Evolution Markets encourages ARB to eliminate the authorization to reverse of trades, and instead institute a penalty for non-compliance should the entity not remedy the deficient transfer request in the allotted time. (EVMKTS3)

Comment: GreenX is increasingly concerned with potential market manipulation and "gaming of the system" that could result if trades that breach holding limits are reversed. By way of example, suppose an entity entered into a contract to purchase allowances at a predetermined price at a specific date in the future. Further suppose that during the time between the date contract was entered and the date the contract expired, the price of allowances declined dramatically, thereby making the contract out-of-the-money. Under the current provision, said entity could, however, go to the spot market and purchase allowances up to their holding limit, knowing that the futures/forward transaction would be reversed as soon as the excess allowances triggered the holding limit provision. This type of gaming would thwart the development of exchange-traded futures and over-the-counter forward markets, destroying the mechanism by which forward price signals are created. (GREENX2)

> **Response:** Under the revisions made to section 95921(b) in the second 15-day changes to the regulation, we will retain the ability to reverse the recording of a transfer request into the system, but we do not automatically require reversal of an underlying transaction. A transfer would only be reversed if the parties to the transfer request do not correct the deficiency. As deficient transfer requests represent some failure to follow the regulation, the remedy may be the imposition of a penalty instead of reversal.
>
> We understand the concern that parties to an underlying transaction may attempt to use the reversal of a transfer as an option to completing the transaction, but we believe the contracts governing the underlying transaction should address the

failure of either party to adhere to market regulations. In any event, the reversal of a transfer request is not automatic. The filing of deficient transfer requests, as well as the failure to correct such requests, would be subject to financial penalties. The regulation also gives the Executive Officer the ability to suspend or revoke the registration of any voluntarily associated entity and to place conditions on the registration of any covered entity. Between the financial penalties and the ability to control who may participate in the market, we believe we have the tools to remove any economic benefit a market participant may gain from the scenario described in the comment.

We have clarified the distinction between the act of transferring control of a compliance instrument on the tracking system and the underlying agreement in the secondary market between entities which would result in a transfer. We modified section 95920(b) to replace the term “transaction” with the term “transfer request.” This change was made to sections 95920(b)(3) and (4).

The term “transaction” means an understanding among registered entities to transfer the control of an allowance from one entity to another, either immediately or at a later date. The “transfer” of a compliance instrument means the removal of the serial number of a compliance instrument from one account and placement into another account. In the California cap-and-trade program, a transfer will be affected through a “Transfer Request” submitted by an authorized account representative or an alternate authorized account representative to the accounts administrator, in order to register a transfer of allowances between accounts into the tracking system.

L-4. Comment: GreenX, requests ARB to reduce the records retention requirement for transactions from ten years to five years. Regulated exchanges like GreenX are required by the CFTC to maintain transaction level records for five years. To impose a longer record keeping period on exchanges is unnecessarily burdensome and costly. Record retention of this magnitude would require significant hardware investment, an expense exchanges would likely pass on through transaction fees to market participants. (GREENX2)

Response: We imposed the records retention requirement in section 95921(g)(2) because we have minimized the role of the exchange clearing holding account in reporting transfer information, such as in section 95920(b)(3) and 95921(g)(3). We anticipate needing the information for market transaction investigations. Having a long retention period is what allows us to not require the information to be provided as transactions are cleared.

L-5. Comment: ARB proposes changes to this section which apply rules on the conduct of trade to transfers of compliance instruments, rather than “transactions.” IETA welcomes this clarification, as we believe it would have been impractical for ARB to regulate the underlying transactions in a future carbon market. A carbon market that consists of a combination of spot, forward, future, and options transactions would make interpreting the positions of market participants relative to their holding limits difficult, if not impossible. Furthermore, requiring a review of every market transaction by ARB would have had a significant negative impact on market liquidity. As IETA has asserted previously, a lack of liquidity in the market can result in higher transaction costs and higher costs of compliance. IETA has reservations regarding the authority of the ARB Executive Officer to reverse transfers of compliance instruments. Markets underlying the cap-and-trade program rely on the certainty of transactions, in which the transfer of compliance instruments is completed based on agreed upon terms and cannot be reversed. IETA understands ARB's need to create a mechanism for the enforcement of the holding limit and to ensure compliant requests for transfer of compliance mechanisms. However, reversals of non-compliant trades could result in market disruptions that, again, are likely to restrict market liquidity. IETA recognizes, however, that ARB has proposed significant changes to this section to allow for a cure period in the event of deficient transfer requests. The ability for transferees to correct deficient transfer requests within three days of notification of the deficiency (and within five days in the event of a retroactive notification) is a considerable improvement. Previously, ARB only had the authority to reverse trades, which would have forced entities to automatically unwind trades in the event of a deficiency. This would result in the market disruptions described above. Although the current draft of this section is an improvement, IETA believes a host of unintended consequences could result from ARB's ability to reverse trades in instances of transfer requests that exceed an entity's holding limit. As IETA has stated previously the reversal of a transfer could result in a daisy chain of entities exceeding holding limits stemming from counterparties forced to take back transferred allowances. More importantly, the ability of a regulator to reverse trades undermines the core tenant of markets that trades cannot be reversed. The result could be a lack of confidence in the California carbon market and the inability of regulated exchanges and other trading venues to develop the infrastructure necessary for a transparent and fair market. This is perhaps why we are not aware of another cap-and-trade program existing that provides its regulatory such trade reversal authority. This authority also provides an opportunity for gaming of the market. For instance, an entity taken over its holding limit by an allowance transfer could use ARB's reversal authority to have allowance purchases reversed that it believes are outside of its commercial interest. For instance, the entity could choose to allow ARB to reverse a trade that is out of the money, thereby using regulatory powers to financial benefit. Therefore, IETA recommends ARB eliminate the transfer reversal authority from the regulations. Instead, ARB can retain the new language providing for a cure period, and at the end of the cure period impose a penalty pursuant to section 96013 should the entity not reduce its holdings to below the holding limit or rectify a deficient transfer request. (IETA4)

> **Response:** We disagree with the conclusion reached in the comment that having ARB retain the right to refuse recording a deficient transfer request undermines the market. We contend that markets will rely on the integrity of our record of ownership in order to function. Under the modifications made to section 95921(b), we retain the ability to reverse the recording of a transfer request into the system, but we do not automatically require reversal of an

underlying transaction. A transfer would only be reversed if the parties to the transfer request do not correct the deficiency. As deficient transfer requests represent some failure to follow the regulation, the remedy may be the imposition of a penalty instead of reversal.

We understand the concern that parties to an underlying transaction may attempt to use the reversal of a transfer as an option to completing the transaction, but we believe the contracts governing the underlying transaction should address the failure of either party to adhere to market regulations. In any event, the filing of deficient transfer requests, as well as the failure to correct such requests, would be subject to financial penalties which could remove the economic benefits obtained through rule violations. The regulation also gives the Executive Officer the ability to suspend or revoke the registration of any voluntarily associated entity and to place conditions on the registration of any covered entity. Between the financial penalties and the ability to control who may participate in the market, we believe we have the tools to remove the incentives for entities to attempt the gaming scenarios described in the comment. We also will not be left in the position of being unable to remedy transfers we know to be defective and potentially fraudulent.

L-6. Comment: Section 95921(e), “General Prohibition on Trading”, in part, casts ARB in the role of market regulator by prohibiting trades that attempt to mislead or manipulate the market. ARB has stated that it will rely on federal oversight of futures and swaps trading markets under the Dodd-Frank Act, which is now being implemented by the Commodity Futures Trading Commission. However, ARB seeks to fill the gaps in regulation by overseeing the spot and forward trading markets. IETA offers that effective and efficient regulation of environmental trading markets is essential to market confidence and, ultimately, their ability to assist in meeting stated environmental objectives—such as reducing concentrations of greenhouse gases. Overly restrictive market regulation or lack of proper oversight can have the same negative impacts. Therefore, getting market regulation right is essential. IETA is concerned that ARB does not have the proper expertise or resources to effectively oversee the trading market, particularly the forward transaction market. As an environmental regulatory body, ARB has responsibility for environmental compliance, but has not previously overseen a trading market corresponding to these environmental programs. ARB has recently published requests for proposals for an independent market monitor and market monitoring staff training. These are important programs, but only part of the regulatory resources needed to effectively oversee markets. IETA encourages ARB to seek, and the California State Legislature and Brown Administration to provide, the proper level of resources to properly oversee markets. IETA also encourages ARB to continue its close collaboration with the CFTC. (IETA4)

Response: The comment is outside of the scope of the second 15-day changes to the regulation. No response is required. However, we are already pursuing the course of action recommended by the commenter. As mentioned, we have issued a Request for Proposal for a market monitor and have secured resources and expect to issue contracts for market monitoring training for agency staff . We have also secured resources for a Market Surveillance Committee composed of academic experts on markets and resources to conduct readiness testing of auction, reserve sales, financial services, and tracking systems. We are also continuing our discussions with the U.S. Commodity Futures Trading Commission and the California Department of Justice on market oversight and enforcement. Therefore, we believe that we have resources and infrastructure in progress to effectively implement the program.

Purchase Limits, Holding Limits and Beneficial Holding Relationships

L-7. Comment: The Council represents non-obligated entities, as well as large and small obligated entities, including independent power producers, investor owned utilities (IOU), and publicly-owned utilities (POU). BCSE believes that to be successful, the Proposed Regulation must, to the extent possible, prevent market manipulation, provide flexible compliance mechanisms to minimize costs, and not discriminate between large and small obligated entities. However, the Proposed Regulation's auction purchase limit and holding limit may pose problems for larger obligated entities and therefore result in discrimination among and between larger and smaller obligated entities and non-obligated entities. BCSE encourages the Board to reexamine these provisions and whether or not the auction purchase and holding limits should be tied to the size of an obligated entities verified annual emissions. (BCFSE2)

Response: We revised the purchase limit for covered entities from 10 percent to 15 percent. Our examination of emissions and allocations data shows that the new purchase limit will ensure that covered entities can purchase their full emissions obligation, net of allowances directly allocated by ARB, at the auction.

On the liquidity issue for larger covered entities, in the first compliance period, all entities will have the ability to keep up to about 6 million MT of allowances in their holding accounts for trading purposes. This limit increases to over 11 million MT in the second compliance period. We believe this is sufficient for entities to be able to sell into the secondary market in response to short-term price spikes. In addition, if one entity is constrained in its purchases, the allowances will then be purchased and held by entities that are not constrained, so any resulting effect on market liquidity would be negligible.

Currently, we are in discussions with members of the WCI on how we could set holding limits and the purchase limits for a joint WCI auction. As part of those discussions, we are considering the proposal in the comment that the purchase limit be tied to the size of an entity's compliance obligation. If we decide to modify the limits when we link to the other WCI jurisdictions' programs, the new limits will be part of a new regulatory development process for linkage.

L-8. Comment: The use of auction purchase limits can have the unintended consequences of both restricting liquidity and creating an unlevel playing field between entities. Companies with a large compliance obligation will require more annual allowances than the purchase limit at a quarterly auction. This could increase the potential for price manipulation and price spikes by limiting a company's ability to sit an auction out if prices are excessively high in that particular auction. In addition, such companies would have limited ability to buy allowances to sell in the secondary market, which could further reduce liquidity. Finally, this policy could create a situation where some compliance entities are forced to purchase allowances in the secondary market instead of at auction—likely with a markup reflecting the sellers' leverage in the market. IETA re-iterates our request that the purchase limits be revised further in order to increase liquidity and create a level playing field for all entities. IETA recommends that all covered entities be allowed to purchase an amount equal to the greater of either a) the auction purchase limit; or b) their compliance obligation plus the current proposed 4 percent granted to non-covered entities. (IETA4)

> **Response:** We revised the purchase limit for covered entities from 10 percent to 15 percent. Our examination of emissions and allocations data shows that the new purchase limit will ensure that covered entities can purchase their full emissions obligation, net of allowances directly allocated by ARB, at the auction.
>
> On the liquidity issue, in the first compliance period all entities will have the ability to keep up to about 6 million MT of allowances in their holding accounts for trading purposes. This limit increases to over 11 million MT in the second compliance period. We believe this is sufficient for entities to be able to sell into the secondary market in response to short-term price spikes. In addition, if one entity is constrained in its purchases the allowances will then be purchased and held by entities that are not constrained, so any resulting effect on market liquidity would be negligible.
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> Currently, we are in discussions with members of the WCI on how we could set holding limits and the purchase limits for a joint WCI auction. As part of those discussions, we are considering the proposal in the comment that the purchase limit be tied to the size of an entity's compliance obligation. If we decide to modify the limits when we link to the other WCI jurisdictions' programs, the new limits will be part of a new regulatory development process for linkage.

L-9. Comment: IETA reiterates its recommendation that purchase limits and holding limits be replaced with more frequent auctions, for example on a monthly basis. Based on recent experience, many will point to RGGI's quarterly frequency and bidding rules as a relatively simple and straight-forward auction design, which is well understood and accessible to a host of entities. While a quarterly auction might be appropriate for small jurisdictions with low demand, IETA believes the implementation of a quarterly auction schedule becomes inconsistent with recent research and analysis conducted in connection with the management of allowance auctions in the EU ETS. Based on analyses, starting in 2013 the EU requires that all regional allowance auctions be conducted on a weekly basis (if not more frequently). The European Commission's decision to hold frequent auctions was driven by the large volume of allowances going to auction in the future, as well as the desire to curb potential price spikes, price volatility, and opportunities for market manipulation. In light of the above, California officials might want to consider timing the frequency of its allowance auctions based on the number of allowances to be auctioned over each period. Weekly auctions are likely to work well in jurisdictions with a large pool of allowances, such as the EU ETS. However, in jurisdictions with constrained coverage and/or large gratis allocations, weekly/monthly auctions could exhibit such small available volumes as to make auction participation high-cost with relatively low-value. IETA welcomes the opportunity to meet with officials to discuss auction design, frequency options and trade-offs. (IETA4)

> **Response:** The comment is outside of the scope of the second 15-day changes to the regulation. No response is required. Nevertheless, our stakeholder consultations held in 2009 and 2010 brought up other factors affecting our decision to hold quarterly auctions. First, stakeholders did believe the quarterly format was operating successfully at the time. Second, both stakeholders and ARB staff were concerned with the ability of all covered entities to participate in frequent auctions due to the costs and time commitments. Some California-covered entities have extensive experience with auctions and commodity markets, and have resources to conduct extensive auction and secondary carbon market participation. Others do not. We believe that retaining the quarterly format will give covered entities time to develop the capabilities for more frequent auction participation. Third, ARB has not operated auctions or financial activities on this scale before, and we must develop the contract services, internal procedures, and enforcement mechanisms needed for successful implementation. We note that the EU ETS auctions are generally conducted by national ministries with extensive experience in market operations. Auctions pose no great institutional challenges for them.
>
> We conclude that the quarterly format can be successfully implemented without damaging the market. At the same time, we do see some value in evaluating a potential move to a more frequent auction once we develop the institutional capability, stakeholders develop familiarity with the process, and we can review a longer period of market information from the EU ETS.

L-10. Comment: ARB should allow agents to acquire and transfer compliance instruments for beneficial holding directly to their own Compliance Accounts. From there, the compliance instruments could later be transferred to one or more of their principals' Compliance Accounts. ARB's proposed rules regarding the disclosure of beneficial holding relationships would then apply. Specifically, agents must report the identity of the principal(s), their account information, and the nature of the relationship to the Executive Officer. SCE proposes that agents, both annually and as-needed, inform ARB of the specific facilities for which they will be procuring beneficial holding allowances for compliance in the following calendar year. This will provide a baseline for the Executive Officer to ensure that agents do not abuse this rule by drastically over-procuring compliance instruments, and thus circumventing the intent behind holding limits. Once it is established that an entity will act as an agent in this type of beneficial holding relationship, SCE proposes that ARB should allow the agent to purchase allowances–either in the auction or the secondary market–and place them directly in its own compliance account. ARB should then allow the Executive Officer to transfer compliance instruments from the agent's Compliance Account to the principal's Compliance Account upon the agent's request. Until such transfer is initiated, such compliance instruments that are added to the agent's compliance account for beneficial holding will be subject to the agent's Compliance Account-based limited exemption. In order for agents to temporarily hold allowances for their principals in this way, their Compliance Account-based limited exemption to the holding limit would need to be expanded. SCE suggests that ARB calculate this increase as the sum of the positive or qualified positive verification statements from the previous year of all of the principals' facilities with which the agent has a beneficial holding relationship. The identity of these facilities will be reported to ARB at least annually, as described above. This amount, which may be referred to as the "Beneficial Holding Compliance Instruments Limit," would be added to the limited exemption from the agent's holding limit. After the compliance instruments have been transferred to the principal's Compliance Account, they would be captured under the principal's limited exemption calculations. Meanwhile, because the compliance instruments are still subject to the existing limitations on the Compliance Accounts, there is no economic incentive for the principal to simultaneously over-procure compliance instruments and place them in their own Compliance Account, which could violate the intent of holding limits and the Compliance Account-based limited exemption to the holding limit. While increasing the holding limits for entities such as electric distribution utilities would be the most simple and effective solution to utility holding limit concerns, the proposal described here may serve to address concerns while maintaining the general structure of the beneficial holdings language. (SCE4)

> **Response:** We disagree and did not make the changes suggested for two reasons. First, the procedure in section 95834 is voluntary and requires the active participation of both principal and agent. This approach is needed to ensure that the principal can manage its accounts under the holding limit without being subject to unilateral actions by the agent. Second, the proposed changes would require us to completely restructure the rules governing compliance accounts, and add a number of new procedures for agents to give instructions to the Executive Officer on the disposition of allowances in compliance accounts.

L-11. Comment: The beneficial holding language in sections 95802(a)(28) and 95834 has significant inconsistent, uncertain, and unfeasible provisions. As currently structured, this language would at the very least create major market issues and potentially prove to be completely unworkable. Certain aspects of the beneficial holdings provisions, specifically those relating to the "Disclosure of Beneficial Holding," are not clear. Section 95834(b)(2) lays out a process whereby a principal must confirm a transfer of allowances. However, it is not clear which transfer must be confirmed—the initial transfer to the agent's account, or the transfer between the account of the agent and the principal. In addition, although this section refers to "transactions," it references only the provisions for "trading" in Section 95921(a). Thus, an agent that bids into

ARB's auction has no guidance on acquiring allowances for beneficial holding purposes. SCE offers one possible interpretation of these provisions: an agent must earmark allowances for a specific principal before purchasing these allowances from an auction or in the secondary market. The principal for which the agent is procuring must agree to this purchase, and also approve the transfer of these allowances into the agent's holding account. Upon transfer into the agent's holding account, these allowances count against the principal's holding limit. The agent will have up to one year to transfer these allowances into the principal's holding account. SCE has numerous concerns with the draft provisions under this interpretation. They include the following:

- For entities such as SCE, who are likely to enter into multiple agent-principal relationships due to a large and varied contractual portfolio, it would be very problematic to earmark allowances to specific principals before acquiring the allowances; this will result in inefficient processes.
- Requiring principals to agree to each compliance instrument purchase adds numerous complications and could completely disrupt the bilateral market and auction process. In addition, requiring a principal's approval to transfer allowances to an agent's account will give the principal a "veto power" to reject any purchase or transfer without having to provide any justification.
- Accounting for the allowances that are in all of the agents' accounts when calculating the principals' holding limits will likely place a large administrative burden on ARB. (SCE4)

Response: Section 95834(b)(2) refers to the agent "acquiring" a compliance instrument on behalf of a principal, while transfer to the principal is described in section 95834(b)(3). Therefore, section 95834(b)(2) cannot be reasonably construed to refer to the transfer between the account of the agent and the principal, as suggested in the comment, so the meaning is clear.

The comment suggests that the reference to section 95921(a) in section 95834(b)(2) is vague, as it seems to refer to the whole section on "trading." We contend there is nothing unclear about the references. First, the reference in section 95834(b)(2) to section 95921 is not to trading in general, but explicitly to "submitting a transfer request." Since section 95921 begins with the process for transfers between accounts, and continues with other rules applying to transfers, the reference is clear. Second, the reference in section 95834(b)(2) referring to section 95921(a) clearly refers to the time limit for submitting transfer requests which is contained in 95921(a). Again, the reference is clear.

There is no requirement that allowances be "earmarked" prior to their being acquired. The transfer request is the disclosure mechanism, so the disclosure does not happen before the allowances are acquired.

It is not clear why having both parties to a beneficial holding confirm a transfer would disrupt the bilateral market or the auction. Nothing prevents the agent from purchasing on its own account. The principal cannot "veto" such transactions. The beneficial holdings arrangements only apply when the agent wants some of its holdings to be counted against the principal's holding limit and the principal agrees.

We are aware of the workload for ARB associated with various provisions of this regulation. While we appreciate the comment's concern, we believe the workload is manageable.

L-12. Comment: In sections 95921(c)(4) and (5), disclosure of unnecessary information will place significant unnecessary reporting burden (i.e. Time of transaction, time of settlement, price) and should be deleted. (CCEEB4)

Response: We removed the requirement for the transfer request to include the time of the transaction agreement and the time of settlement. However, the remainder of the comment is outside the scope of the second 15-day changes to the regulation because we did not modify the text referred to in the comment, so no response is required.

L-13. Comment: The Holding Limit Should Address the Magnitude of an Obligated Entity's Compliance Obligation and Not Discriminate Among or Between Obligated Entities.

The holding limit, as currently proposed, unfairly limits the ability of large obligated entity's such as large independent generators to use the flexible compliance mechanisms provided by CARB, including unlimited banking of allowances. As a result of this limitation, some large entities will have to surrender enough allowances to meet their total annual emissions, rather than using the flexible compliance period to decide when to submit their allowances, in order to avoid exceeding the holding limit. IEP notes that CARB here again essentially exempted utilities from this provision through the creation of a new "beneficial holding relationship" which affords the IOU's significant flexibility in managing their contractual obligations and requires the purchased allowances to count against the IPP's holding limit; although, they may not physically take ownership for up to one year [Section 95834(b)(3)]. This puts independent generators at a competitive disadvantage to IOUs. In addition, the regulation recognizes that limiting an entity's flexibility is punitive because it authorizes the Executive Officer to impose sanctions on registered entities that violate the provisions of the Cap-and-Trade Regulation, including increasing the annual surrender obligation for a covered entity. Thus, as proposed, the holding limit imposes this penalty on large generators (and not IOUs) for no other reason than their sheer-size.

While IEP shares CARB's concerns regarding hoarding, market manipulation, etc, there needs to be a mechanism in place to address the compliance needs of large obligated entities where the current holding limit potentially creates discriminatory impacts, with respect to flexible compliance instruments.

In order to compensate for these disparate impacts on obligated entities, CARB should adjust the holding limit calculation for large obligated entities to reflect the different magnitudes of compliance obligations among obligated entities. IEP requests CARB amend the regulation prior to the first auction in 2012 so that the holding limit is tied to the size of an obligated entity's compliance obligation. (IEPA3)

Response: The comment on the structure of the holding limit is outside the scope of the second 15-day changes to the regulation because we did not modify the structure of the holding limit, so no response is required.

The comment on section 95834 on beneficial holdings is within the scope. However, we disagree with the comment. The comment claims that utilities will have flexibility not afforded to generators when utilities are allowed to count allowances held pursuant to section 95834 against the holding limit of the generator. However, the comment ignores section 95834(a)(3)(A), which requires a principal to confirm the existence of a beneficial holdings relationship, as well as sections 95834(b)(2) and (3), which require the principal to be notified of any action taken by an agent and to confirm that action. Thus, the arrangement is entirely voluntary, and the utility does not gain any flexibility not approved by the principal. The notification and confirmation provisions ensure that the utility serving as agent does not gain a competitive advantage over the principal. The result is an entirely voluntary path allowing utilities and generators to accumulate and transfer allowances to cover emissions from contracted generation.

L-14. Comment: Holdings limits are intended to prevent one entity from cornering the market. However, this also places significant strain on many compliance entities. Auction frequency would ostensibly alleviate the concern of one entity concerning the market while creating more liquidity within the market. CCEEB recommends moving towards monthly auctions in order to avoid the need for holding limits. (CCEEB4)

Response: The comment is outside of the scope of the second 15-day changes to the regulation. No response is required. However, we disagree with the comment's assertion that more frequent auctions would eliminate the need for the holding limit. The limit is needed to prevent concentrated holdings through multiple auctions and secondary market purchases. More frequent auctions, however, could deal with some of the manipulative acquisition strategies that we intend to prevent through the auction purchase limit.

Currently, we are in discussions with members of the WCI on how we could set holding limits and the purchase limits for a joint WCI auction. As part of those discussions, we are considering the proposal in the comment that the purchase limit be tied to the size of an entity's compliance obligation. If we decide to modify the limits when we link to the other WCI jurisdictions' programs, the new limits will be part of a new regulatory development process for linkage.

L-15. Comment: WPTF has previously raised a concern that the holding limit will disadvantage capped entities with large compliance obligations. Because the holding limit is set at the same level for all entities, regardless of the scale of each entity's compliance obligation, some entities would be able to purchase and hold a quantity of allowances significantly higher than their compliance obligation while other entities would not even be able to hold sufficient allowances to cover their obligation in a single year. The holding limit thus discriminates among capped entities, and will hinder the ability of some entities to effectively manage their compliance with the cap and trade program, to the likely benefit of those entities who are not subject to the same restrictions. WPTF recommends that CARB review and modify the auction purchase and holding limits to ensure that they are equitable to all capped entities and do not impair their ability to comply with the program. (WPTF3)

> **Response:** We revisited the purchase limit and revised it from 10 percent to 15 percent to ensure that all covered entities will be able to purchase their allowance needs, net of direct allocations, at the auction. In the first 15-day changes to the regulation, we revised the limited exemption to the holding limit, to ensure that covered entities could accumulate, in advance if needed, more than enough allowances to meet their compliance obligations.

L-16. Comment: The ongoing monitoring and reviewing of the allowance market, and particularly the auctions and availability of allowances in the Reserve Account, are crucial elements needed for the success of the entire program. NCPA urges CARB to pay close attention to the start-up procedures and market simulations, and to include provisions in the Regulation, or at a minimum, in a Resolution approving the revisions to the Cap-and-Trade Program, that will allow the agency to delay the initial auction if problems are discovered that cannot be timely corrected. While NCPA understands CARB's eagerness to move forward with the program and begin auctions for allowances in the second half of 2012, doing so without a full analysis of potential problems will have more adverse ramifications than delaying the auctions at the onset of the program. (NCPA4)

> **Response:** No response is required.

L-17. Comment: NCPA supports the Proposed Revisions to section 95833 that increases the threshold for determining a "direct corporate association" from 20 percent to 50 percent, as well as the intent of the provision to "apply only in instances where one entity has clear control over another." (NCPA4)

> **Response:** Thank you for your support.

L-18. Comment: NCPA fully supports the Reserve Account established in section 95831(b)(4), but continues to be concerned that the Proposed Revisions to this section do not include a mechanism to ensure the availability of allowances in the Reserve Account. Since this account is created as a means by which to ensure that allowances prices are contained in the market, it is imperative that there be an ample supply of allowances in the Reserve Account for compliance entities to purchase in the event that the market is not stable. NCPA joins with other stakeholders in urging CARB to ensure that there is mechanism in place to guarantee a minimum number of allowances in the Reserve Account throughout the duration of the Cap-and-Trade Program. (NCPA4)

Response: No response is required.

L-19. Comment: ARB has stated that the holding limits are required to ensure the market is not manipulated. WSPA believes that it is critical that controls be in place to prevent market manipulations, but we disagree with the one size fits all holding limit. We are additionally concerned with the deletion of the provision that excluded application of holding limit for associated entities that were prohibited by regulations from coordinating market activities. WSPA believes that this provision should be reinstated. We do not believe that there is any support for forecasting that disruptions in the allowance market are likely to occur between entities prohibited by regulations from coordinating market activities. We recommend ARB reject the proposed deletion of the provision in section 95920(f) and return the original language. (WSPA4)

Response: We removed the text from section 95920(f) because in that location the exemption only applied to the holding limit. We replaced it with new language that was added to section 95833(a)(4), so that it would apply to the corporate associations determination itself.

Outside the Scope of the 15-Day Changes to the Regulation

L-20. Comment: A large number of deliveries of exchange contracts occur on a single day, or several days, throughout the course of a calendar year. On these specific days, millions of allowances may pass through clearinghouses' registry accounts. To facilitate timely and accurate deliveries, the clearinghouse will often dedicate the entire Deliveries Team (five to ten staff members) to the process. By allowing up to ten users access to the exchange clearing holding account, these risks will be mitigated. Modify section 95832 as follows:

(i) For exchange clearing trading accounts, the authorized representative may designate up to ten delivery analysts responsible for the account to directly access the account and assist in performing the functions of an entity meeting the requirements of 95814(a)(3) and making submissions pursuant to 95832(h). (GREENX2)

Response: The comment is outside of the scope of the second 15-day changes to the regulation. No response is required.

L-21. Comment: CalChamber is concerned that CARB intends to fill the allowance reserve, which was intended to be a cost-containment mechanism, with allowances from the haircut. These are allowances that should otherwise be freely allocated in order to minimize emissions leakage. Instead, CARB is proposing to profit at industry's expense by selling the reserve allowances at arbitrarily high prices, a major concern for CalChamber. This proposal negates the purpose of an allowance reserve as a cost-containment measure by increasing program cost with no overall program benefit. (CALCHAMBER4)

> **Response:** The comment is outside of the scope of the second 15-day changes to the regulation. No response is required.

L-22. Comment: Price containment in the proposed allowance reserve is necessary if the reserve is to be a true cost-containment mechanism. (CALCHAMBER4)

> **Response:** The comment is outside of the scope of the second 15-day changes to the regulation. No response is required.

L-23. Comment: While many of the changes in the market design (such as increased purchase limits) will have a positive effect on developing an efficiently functioning market for all participants, several significant policies remain that threaten to diminish the effectiveness of the market and hinder economic recovery. The holding limit provision creates inequitable impacts on larger covered entities imposing constraints on their ability to participate in the market and optimize trading activity and requiring earlier surrender of allowances compared to those less impacted by the holding limits. (CHEVRON4)

> **Response:** The comment is outside of the scope of the second 15-day changes to the regulation. No response is required.

L-24. Comment: The changes made in the definition of affiliates mark a significant improvement in the cap and trade rule. However, it would be helpful to obtain clarification on section 95833(1) (A) to ensure that a right of first refusal is not equated *with the "right to acquire" or "option to purchase" so that an entity is not deemed to have* a corporate association with another merely because it holds a priority right to obtain an interest in that other entity exercisable only when that interest is being offered to a third party. A "right to acquire" or "option to purchase" means that the power to trigger the transaction rests with the potential buyer. In other words, the "buyer" initiates the sale by exercising the right/option to purchase the shares. This differs from a "right of first refusal" in which the authority to trigger the transaction rests with the owner, and the buyer only has the right to be offered the shares the owner decides to sell. See, e.g., Campbell v. Alger, 71 Cal.App.4th 200, 206-207 (1999) (A right of first refusal is the conditional right to acquire property, depending on the owner's willingness to sell. The right does not become an option to purchase until the owner of the property voluntarily decides to sell the property and receives a bona fide offer to purchase it from a third party). (CHEVRON4)

> **Response:** The comment is outside of the scope of the second 15-day changes to the regulation. No response is required.

L-25. Comment: ARB's Proposed Rule on Holding Limits has a discriminatory impact on large covered entities. The primary problem with the proposal on holding limits is that, instead of treating all entities within the same sector equally, it arbitrarily discriminates against and penalizes large covered entities, the very companies that have the most resources invested in the State of California. Because the current holding limit is lower than the compliance obligations of certain large covered entities but higher than the compliance obligations of all smaller covered entities and non-covered entities, large covered entities will be required to comply with the cap-and-trade program earlier than the smaller covered entities. This disparity has a significant economic impact on the large covered entities. For example, assuming Chevron gradually acquires or holds allowances to track its emissions, the holding limit will require Chevron to comply earlier than its competitors by transferring into its compliance account significantly more allowances than the 30 percent prescribed in the proposal for 2013. As illustrated in the chart below (which is based on the most recent publicly available information), no other covered entity operating in the oil and gas sector will be impacted by the holding limit in 2013. As allowances moved into a compliance account cannot be withdrawn, the holding limit essentially requires Chevron to comply with the cap-and-trade program ahead of the prescribed deadline, in this case 16 months before any other entity in its sector. This design flaw will distort the market and make it more costly for Chevron to comply relative to its competitors, for no overall market benefit or rational policy objective. The problem is only exacerbated during the second compliance period; by 2017, based on data provided to us by Chevron, we estimate that the number of allowances Chevron will need to move into its compliance account will exceed 100 million, whereas its closest competitor in the sector will have to move less than 50 million allowances into its compliance account in order to comply with the holding limit. In addition, the holding limit will effectively preclude large compliance entities such as Chevron from minimizing their compliance costs by participating fully in the market. Although it is difficult to accurately value this opportunity cost, the prohibition is a significant limitation on the ability of these entities to use market mechanisms to comply with their legal obligations in the most efficient manner. (CHEVRON5)

> **Response:** The comment is outside of the scope of the second 15-day changes to the regulation. No response is required.

L-26. Comment: The holding limits are unprecedented and unsupported by the record. As we pointed out in our August letter, there is no data or research that demonstrates or otherwise purports to show precisely what positive impact the holding limit rule will have on the carbon market. The holding limits contained in section 95920 of the Regulations are derived from a rule designed by the CFTC to govern futures markets, in which regulators' leading concern was systemic risk, not market manipulation. ARB has pointed to no evidence supporting the extension of a rule designed for futures markets to the inventory market at issue here. Whereas systemic risk is indeed an issue in large, highly liquid futures markets, such risks will be non-existent by design in the California allowance market, where large covered entities will be engaging in the market primarily for compliance purposes and where relatively few counterparties will be exposed to any risk associated with such entities' market positions. Indeed, it is important to reiterate the conclusions presented in our August Letter, which explained that there are no other commodities markets and no other major carbon markets in existence, either compliance or voluntary, including the German, French, UK and EU-wide emissions trading systems, with a holding limit. The only rationale ARB has provided to justify its approach to holding limits is contained in its "Staff Report: Initial Statement of Reasons" released in October 2010. In that report, ARB cites the conclusions of Jeffrey H. Harris, a professor of finance at the University of Delaware and the author of a report on holding limits prepared for the Western Climate Initiative Markets Committee (the "WCI Report"). Yet this WCI report is not part of the record and was not subject to any notice and comment rulemaking procedures. Had ARB formally included the WCI Report in the record, stakeholders would have had the opportunity to examine its conclusions and raise concerns about the applicability of Dr. Harris' logic to the specifics of the California carbon market. Specifically, stakeholders may have noted that the proposed limit is set below the compliance obligations of certain covered entities, a fundamental flaw that Dr. Harris never identified, discussed or justified in the WCI Report. In fact, Dr. Harris conducted his analysis for WCI at a time when multiple states and provinces were expected to join WCI. Since the holding limit is a function of the size of the cap, Dr. Harris' discussion and conclusions are based on market conditions that feature a much higher cap, at least double that of California's, that will not exist under the California proposal. Accordingly, the WCI Report is a poor tool to help guide policy decisions for the California carbon market. (CHEVRON5)

> **Response:** The comment is outside of the scope of the second 15-day changes to the regulation. No response is required.

L-27. Comment: Covered entities should be allowed to hold the number of allowances needed to satisfy their compliance obligations. We recommend this change to address the increased costs and added burdens solely borne by large covered entities, which would maintain the holding limit as it is currently configured under section 95920 but exclude from the limit the number of allowances needed by a covered entity to comply with its compliance obligation during the applicable compliance period. Accordingly, a covered entity holding the number of allowances equal to its compliance obligation is placed in the same position, for holding limit purposes, as a non-covered entity that does not hold a single allowance, thereby creating a level playing field among all market participants and entities within the same sector. It is imperative that the appropriate changes to the holding limit are made now as opposed to next year or some other time in the future. Waiting until the future will result in a loss of the momentum necessary to make such changes, and implementing changes after the adoption of the Regulation could prove to be cumbersome, may result in confusion by market participants (including in connection with their underlying investment strategies) and would introduce unnecessary regulatory risk prior to any such adoption. Modify section 95920(d)(2)(A) as follows:

(2) ~~A Limited Exemption from the Holding Limit is calculated as:~~The limited exemption is the number of allowances which are exempt from the holding limit. (CHEVRON5)

Response: The comment is outside of the scope of the second 15-day changes to the regulation. No response is required.

L-28. Comment: The holding limit has a flaw that may allow speculators to exert excessive market power. Because the policy fails to distinguish between covered and non-covered entities, it may, under certain circumstances, exacerbate the possibility for market abuse, the precise outcome the holding limit policy was designed to mitigate. When a large covered entity such as Chevron is forced to shift allowances into its compliance account to comply with the holding limit, the size of the market will effectively shrink. Depending on the degree to which large covered entities must move allowances into their compliance accounts in order to comply with the holding limit, the policy may create a considerable reduction in market volume, effectively reducing liquidity. By constraining the amount of allowances circulating freely in the market, the holding limit policy increases the probability that any one market participant, including a trader or speculator, can acquire a position that would allow it to exert market power. (CHEVRON5)

Response: The comment is outside of the scope of the second 15-day changes to the regulation. No response is required.

L-29. Comment: IETA understands that ARB views an allowance holding limit as a mechanism to reduce the possibility of a market participant exercising allowance market power. However, holding limits are likely to prove ineffective in this regard, and may create unintended consequences because they will severely limit market liquidity, thus creating conditions that could allow certain entities, including speculators, to exert undue market power in an illiquid trading environment. The potential for price manipulation and the exercise of market power is greater in illiquid markets, even if a quantitative restriction on holding permits prevents a single entity from acquiring undue market share. This is due to the fact that non-covered entities and other market participants can gain the ability to shape prices in secondary allowance markets and collect unnecessary economic rents through a markup. This incentive for gaming is particularly applicable to large entities with small compliance limits, as they can hold permits above their compliance obligation but below the holding limit, giving them the potential to exert market power over larger entities with more limited flexibility. Furthermore, with these limits in place, larger covered entities will face greater pressure to participate in all auctions regardless of price conditions. They have limited ability to hold allowances to offset this price risk, and are unable to then provide allowances back to the market when the market is short. This inflexibility will raise the compliance cost for these entities, which will be passed on to ratepayers. Counterparties in these transactions can, at the same time, extract economic rents from selling allowances for a markup to large covered entities forced to purchase. Based on the aforementioned arguments, IETA continues to recommend that holding limits be discarded. If holding limits are retained, IETA recommends that at a minimum they be adjusted to reflect, in addition to the amounts held in non-trading compliance accounts, the greater of either the holding limits currently proposed in section 95920 or a quantity equal to a covered entity's compliance obligation. (IETA4)

Response: The comment is outside of the scope of the second 15-day changes to the regulation. No response is required.

L-30. Comment: ARB has announced a one-year delay of the compliance elements of the cap-and-trade program, which SCE enthusiastically supports. The additional time is crucial for allowing greater scrutiny and adequate independent testing of the auction and market design. (SCE4)

Response: The comment is outside of the scope of the second 15-day changes to the regulation. No response is required.

L-31. Comment: ARB has also indicated that it will open a 45-day rulemaking in 2012 to address market readiness and market testing issues. SCE supports the decision to open a new rulemaking, and strongly urges ARB to begin this process as soon possible. Because market readiness is key to the success of this regulation, this new rulemaking should be completed well before the launch of the first allowance auction. As part of the market testing and readiness rulemaking, ARB should re-evaluate the Allowance Reserve, which was designed to allow covered entities a means for cost containment. ARB staff has made several important revisions to the Allowance Reserve, including allowing allowances unsold at auction to be returned to the general market rather than into the Allowance Reserve. In the impending rulemaking, ARB staff should continue to improve the rule by identifying a means to refill the reserve in the event that it is stressed, or when at least one-third of the allowances it contains are sold. Electricity markets move and fluctuate rapidly, and it is critical that ARB develop an approach in advance of any adverse market event to refill the Allowance Reserve.

SCE looks forward to a collaborative process with ARB staff and stakeholders to design a cap-and-trade auction and market that limits gaming opportunities and the risk of another electricity crisis. (SCE4)

Response: The comment is outside of the scope of the second 15-day changes to the regulation. No response is required.

L-32. Comment: SCE reiterates its position that the holding limit for a regulated electric company should be based on its annual GHG cost exposure (using the annual allowance allocation as a proxy). California IOUs such as SCE have no incentive to speculate in their energy and energy-related procurement activities, including the purchase and sale of GHG compliance instruments. These activities are governed by the IOUs' CPUC-approved AB 57 Bundled Procurement Plans, and are conducted on a cost-pass-through basis, with their customers paying for all the costs and receiving all of the benefits. There is no opportunity for IOU shareholders to make any profit under these plans. Because the CPUC will maintain its regulatory oversight of the IOUs, ARB should recognize that the IOUs are not at risk of manipulating or speculating in the GHG compliance instrument market. Rather, SCE and the other IOUs have strong interests and obligations to hedge customer price risk efficiently and effectively, subject to the oversight and direction of the CPUC. ARB should adjust holding limits for the regulated electric distribution companies to allow them to mitigate their GHG cost exposure and protect their customers from significant financial risk. The new market design and testing rulemaking is an appropriate venue for reevaluating these holding limits to improve them further. In the meantime, modest adjustments must be made before the final regulations are submitted to the Board for approval, in order to create a workable framework before the cap-and-trade program officially begins. We recommend ARB adjust the holding limits based on a regulated entity's GHG market exposure while recognizing that regulated utilities such as SCE will be unable to manipulate the market. Modify section 95920(d)(1) as follows:

(1) The number given by the following formula:
Holding Limit = <u>the greater of</u>
<u>1)</u> 0.1 * Base + 0.025*(Annual Allowance Budget – Base)

In which:

"Base" = 25 million metric tons of CO_2e<u>, or</u>
<u>2) an individual utility's allowance allocation for that same year as defined in Table 9-3.</u> (SCE4)

Response: The comment is outside of the scope of the second 15-day changes to the regulation. No response is required.

L-33. Comment: Minimize unnecessary bureaucratic requirements. Investment grade credit-rating should be permitted in lieu of bid guarantees in sections 95912(h) and 95913(e)(2). (CCEEB4)

Response: The comment is outside of the scope of the second 15-day changes to the regulation. No response is required.

L-34. Comment: Deadlines should be established for ARB decision-making processes to provide entities with a degree of certainty. Modify sections 95830(e) and 95912(l)(2) as follows:

(e) Completion of Registration. Registration is completed when the Executive Officer approves the registration and informs the entity and the accounts administrator of the approval. <u>The executive officer shall approve or deny a registration application within 30 days of submittal.</u>

(2) After certification, <u>immediately</u> direct the financial services administrator to: (CCEEB4)

Response: The comment is outside of the scope of the second 15-day changes to the regulation. No response is required.

L-35. Comment: CCEEB supports ARB's decision to contract with an independent market monitor. Market monitoring is essential to help ensure reasonable market behavior and results, and to instill confidence with market participants and other stakeholders. CCEEB recommends that the Independent Market Monitor that ARB selects be established with authority to: (1) review the auction and certify results prior to any consummation of any trades from that auction prior to the running of any auction; (2) provide analysis of the competitiveness of any auction, preferably on an ex-ante basis (e.g. prior to running the auction); and (3) report findings and concerns to the ARB. (CCEEB4)

Response: The comment is outside the scope of the second 15-day changes to the regulation. No response is required.

L-36. Comment: The holding limit is too low for regulated entities with large compliance obligations and may be unnecessarily high for entities that lack any compliance obligation. As amended, significant amounts of allowances, for large compliance entities will be locked in compliance accounts. This creates an uneven playing field that favors traders over regulated entities. Compliance entities, especially those with large compliance obligations, must be able to hold and trade a larger portion of their allowances to adequately manage their risk throughout the cap-and-trade program. (CCEEB4)

Response: The comment is outside of the scope of the second 15-day changes to the regulation. No response is required.

L-37. Comment: We propose that ARB revisit the issue of holding limits in section 95920(d), as they create a number of market inequities created by the "one size fits all" holding limit, regardless of an entity's compliance obligation. ARB reasons that large entities can hold the necessary allowances for compliance by placing allowances into their compliance account. However, once there, entities are precluded from later selling these allowances, which may be required to manage the cost exposure associated with a fluctuating carbon price. Restricting the number of allowances an entity can freely hold to less than an entity's annual compliance obligation is fundamentally discriminatory against entities with large compliance obligations, and does not create a level playing field between market participants. In fact, it punishes companies who have invested more in California and rewards competitors in the same sector who have invested less. In addition, such a policy will exacerbate potential hoarding, as many entities that may want to sell their bank of allowances will be prevented from doing so. This will artificially drive up the cost of compliance. Finally it will also reduce market activity and liquidity, another cost driver, by reducing the number of allowances available in the market because larger compliance entities will be required to comply earlier and retire allowances to avoid violating the arbitrary holding limits. This action, in turn could constrain the supply of allowances available in the market. To our knowledge, no other cap and trade program imposes holding limits on market participants. We recommend ARB allow holding limits up to compliance obligation levels for covered entities. (WSPA4)

> **Response:** The comment is outside of the scope of the second 15-day changes to the regulation. No response is required.

L-38. Comment: ARB's regulations still impose a "one size fits all" holding limit, regardless of an entity's compliance obligation. ARB reasons that large entities can hold the necessary allowances for compliance by placing allowances into their compliance account. However, once there, entities are precluded from later selling these allowances, which may be required to manage the price exposure associated with a fluctuating carbon price. Restricting the number of allowances an entity can freely hold to less than an entity's annual compliance obligation is fundamentally discriminatory against entities with large compliance obligations, and does not create a level playing field between market participants. In addition, such a policy will exacerbate potential hoarding, as many entities that may want to sell their bank of allowances will be prevented from doing so. This will artificially drive up the cost of compliance. We recommend ARB allow holding limits up to compliance obligation levels for covered entities. (SHELLENERGY2)

> **Response:** The comment is outside of the scope of the second 15-day changes to the regulation. No response is required.

L-39. Comment: Could the cap and trade regulation cause another and more severe market meltdown? In this case, “follow the money” is good advice for understanding why this regulation is being politically pushed. For example, section 95814 identifies that Voluntarily Associated Entities and Other Registered Participants are allowed to enter the program as “an entity providing clearing services in which it takes only temporary possession of compliance instruments for the purpose of clearing transactions between two entities registered with the Cap-and-Trade Program. A qualified entity must be a derivatives clearing organization as defined in the Commodities Exchange Act (7 U.S.C. section 1a(9)) that is registered with the U.S. Commodity Futures Trading Commission pursuant to the Commodities Exchange Act (7 U.S.C. section 7a-1(a)).

A study by Duke University's Nicholas Institute for Environmental Policy Solutions anticipates that if the United States passes a cap-and-trade law, the derivatives trade will probably exceed the market for the allowances themselves. Banks like JPMorgan Chase, Morgan Stanley, and Goldman Sachs already have active carbon trading desks that deal in instruments connected to Europe's cap-and-trade system and voluntary markets in the United States. Business is expected to explode with expansion of cap-and-trade in the United States. This is not something that has been focused on by most environmentalists. Among environmental groups, there is, understandably, less focus on the finer points of financial regulation. Another article found that the banks are preparing to do with carbon what they’ve done before: design and market derivatives contracts that will help client companies hedge their price risk over the long term. They're also ready to sell carbon-related financial products to outside investors. The International Emission Trading Association acknowledges the concerns and states that they are fixed by the Dodd-Frank Act, but many sources find that the mentioned regulatory fixes to prevent a recurrence of market manipulations and collapse were extremely weak and ineffective, leaving us open to even worse collapses in the future with such continued practices. (CBE3)

> **Response:** This regulation is one of many strategies to address the mandates of AB 32. The market-based program was chosen because it provides the lowest cost-effective way for the regulated entities to reduce GHG's and help achieve the mandates under AB 32. The market-based program also provides the covered entities flexibility in how they can best meet the GHG emissions reductions that are required with the declining cap. By choosing a market-based program, compliance instrument trading will be a feature of the program. As such, we expect participation by clearing houses and financial dealings to occur. We have worked closely with the State Attorney General's office to design a program that is enforceable and to add features to address market manipulation and gaming. ARB will also contract for external experts for a Market Surveillance Committee and Market Monitor to help with oversight of the market program. As part of program implementation, we will continue to work with the State Attorney's Office and CFTC on addressing oversight of the market.

Other Market-Related Comments

L-40. Comment: Section 95831(b)(2) contains an errant reference in subpart (D). The reference should be to section 95857(d)(1)(A), not 95857(d)(a)(A). Also, there should also be a subpart (E), as follows:

> <u>(E) The allowances consigned to Auction by the Executive Officer pursuant to 95831(D).</u> (SMUD4)

> **Response:** We agree and corrected the reference to read 95857(d)(1)(A). We did not add a subpart (E). The commenter's suggested reference was unclear.

M. OFFSETS

Limits on Offsets

No Offsets/Reduce Number of Offsets

M-1. (multiple comments)
Comment: We propose that section 95854 of the revised regulation be modified so that, in the second and third compliance periods, the percentage of total emissions that would be permitted to come from offsets is reduced. We propose that no more than two percent of total emissions in the second compliance period and no more than one percent of total emissions in the third (and any subsequent) compliance period be permitted to come from any type of offset credit. This would be equivalent to roughly one-third of the emission reductions required in the 2nd compliance period, and approximately 15 percent of emission reductions required in the 3rd compliance period. (UCS9)

Comment: We propose that section 95854 of the revised regulation be modified so that, in the second and third compliance periods, the percentage of total emissions that would be permitted to come from offsets is reduced. We propose that no more than two percent of total emissions in the second compliance period and no more than one percent of total emissions in the third (and any subsequent) compliance period be permitted to come from any type of offset credit. This would be equivalent to roughly one-third of the emission reductions required in the second compliance period, and approximately 15 percent of emission reductions required in the third compliance period. These modifications in quantity will help promote technological innovation in the highest emitting sectors, increase opportunities for in-state co-benefits (including air quality benefits), and reduce the risk that a high proportion of compliance credits do not represent real and additional reductions in emissions. (UCS8)

Comment: While 8 percent offsets might sound relatively small, the 8 percent refers to the total emissions, not the total reductions. Table 9.2 of the regulation shows that the nominal cap emission reduction over time is 7.5 percent for some sectors and about 15 percent for others (think of an average for discussion purposes of about 10 percent emissions reductions). This means that 8 percent offsets equals about 80 percent of emission reductions. This issue has been brought up repeatedly by the Union of Concerned Scientists, but has not been addressed by CARB. Given the highly speculative benefit of offsets, counting on 80 percent of them to fulfill the cap and trade aim is unconscionably high. (CBE3)

> **Response:** We did not change the limit on the use of offsets in the program. We believe that a limited use of offsets is necessary in the program to contain costs and incentivize reductions in uncapped sectors. The program imposes a limit on what we believe is an appropriate amount of offsets that an individual covered entity can use for compliance. All offsets used for compliance are real reductions, albeit outside the cap. Allowing a limited number of offsets into the

program provides cost-containment benefits and ensures that some GHG emissions reductions occur within the sectors covered by the cap-and-trade program. The program includes provisions that would allow a maximum of 201 $MMTCO_2e$ of offsets through the year 2020. This limit will be enforced through a limit on the use of offsets by an individual entity equal to eight percent of its compliance obligation. Combined with the Allowance Price Containment Reserve, this limit ensures that reductions from the program come from sources covered by the program at expected allowance prices, while use of the reserve will relax that constraint if prices rise.

Unlimited Offsets/Increase Number of Offsets

M-2. (multiple comments)
Comment: CARB should not continue to set an arbitrary limit on the number of offsets that can be used to meet a compliance entity's surrender obligation. The proposed 8 percent limit is no more likely than the previous 4 percent limit to provide enough offsets to meet the needs of a growing economy in California. As with the arbitrary withholding of necessary allowances for leakage prone industries, this arbitrary limit on the number of offsets that can be used increases costs and leakage. (AB32IG3)

Comment: IETA continues to support the removal of any quantitative usage limits placed on covered entities for using offsets to meet their compliance obligations. As long as only real, permanent, and verifiable offset credits are allowed into the market, usage limits that are small relative to overall compliance obligations will only serve to constrain investment in reductions of greenhouse gas emissions in a cost-effective manner. Offsets provide critical cost-containment and price stability by providing flexibility to covered industries to find the lowest available cost emissions reductions across a range of options. For this reason, IETA continues to recommend that California eliminate the use of quantitative offset usage limits. (IETA4)

Comment: Section 95854 limits the volume of offsets that facilities can use for their annual and triennial compliance obligation to only 8 percent, thus artificially raising the cost of compliance. This restriction, combined with the expected use of auctions as a means to distribute the allowances will marginalize (render inconsequential) the use of offsets, reduce offset supply, discourage out-of-program sources that would otherwise be subject to CARB control (for it is only such sources that can create credits) from taking steps that would have otherwise be taken to reduce emissions, and increase the cost of compliance. Offset creators will be more likely to choose to expend their capital in regions that allow for the greater use of offsets and potential offset buyers will be more likely to choose to expand and possibly move their operations to regions that are not burdened with such restrictions. BGC Environmental Brokerage Services, L.P. recommends that CARB remove the quantitative restriction. Instead, limits should be based on quality of offset credits. Any offset credits which meet CARB's qualitative criteria should be allowed to be used by sources. (BGCEBS)

Comment: California businesses will need access to a pool of verifiable offsets and allowances stating in 2012. Developing a new ARB offset review and approval process to review credits and allowances for use in California that have already been reviewed in the EU is costly and unnecessary. The EU carbon markets produce robust offsets and allowances. Linking to the EU would ensure a supply of high-quality and tradable market instruments for California's carbon market. Relying on a limited market CO_2 cap-and-trade program to reduce emissions in California without linkage to a broad liquid market loses the economic efficiency of the market-based approach and undermines the policy goals. CCEEB recommends expediting linkage and making it a priority to be completed. If linkage is not possible, then CCEEB believes that other cost-containments measures must be adopted to soften the economic impact of this regulation and limit leakage of jobs and emissions. (CCEEB4)

Comment: CCEEB supports the use of high-quality offsets to constrain costs. Although ARB adjusted its limits on the use of offsets, from 4 percent to 8 percent, this limitation is still unnecessary. Arguments in favor of limiting offsets due to localized impacts have been eliminated by the ARB Co-Pollutant Emission Assessment that indicates de minimis co-pollutant co-benefits from quantitative and geographic restrictions of offsets. As such, there is no reason to limit the use of offsets as a compliance instrument. Offset credits should be allowed without any geographical or quantitative restrictions. Restricting offsets generation to projects located within a certain geographic sphere or to those that provide co-benefits is contrary to what should be the fundamental aim of an offsets program, i.e. maximizing GHG reductions at the least cost to mitigate the effects of global warming. Moreover, imposing limits on the use of offsets—either quantitative or geographic—simply raises the cost of the emission reduction program to California residents. This increased cost will affect the ability to reach longer term and increasingly challenging emission reduction targets at a cost that is acceptable to society. Instead, ARB should move rapidly to begin the process to delegate approval of offsets to third party registries, adopt offset protocols, and recognize other national and international offset programs, while establishing a process early for developing projects in California. This will ensure that local benefits are captured while still leading the developing world towards a low carbon future. In addition, the restriction on carrying over unused portions of an entity's offset limit into subsequent compliance periods should be removed. CCEEB recommends that ARB begin the process to delegate approval of offsets to third party registries and adopt new protocols rapidly to ensure that adequate supply is available in the first compliance period. Additional supply options should include use of five additional Climate Action Reserve Protocols; use of offsets from Western Climate Initiative Partners; support the development of Pilot REDD Projects; allow use of Climate Action Reserve Landfill Credits generated before 2012; and approve protocols developed by California air districts, as appropriate. (CCEEB4)

Comment: ARB has not provided documentation that demonstrates how offsets are going to be made available in quantities sufficient to facilitate cost-effective compliance. For example, in the August, 2011 presentation, ARB staff (slide #17) asserts that the maximum offsets demand for the first compliance period (2012-2014) is 26 million metric tons. Yet, in June of 2010, staff asserted (Slide #27) that only 3 million metric tons will be available from sources in California. In fact, only when offsets from Ozone Depleting Substances (ODS) from sources outside California are included, does ARB predict that 30 Million MT of offsets will be available. In other words, only by using virtually all the offsets from outside the State, can ARB assert that the offset supply is adequate during the first compliance period. This is inconsistent with ARB's historic reliance on in-state emission reductions subject to verification by ARB. Indeed, it is not apparent to WSPA members at this time how the very large volume of offsets would be available to all companies for all years as is suggested in the most recent proposal. Finally, we remind ARB that the intent of offsets is to provide options for emission reductions rather than to offset inequities or the effects of arbitrary benchmarks. We recommend ARB remove the 10 percent reduction in free allowances so that the demand on supply matches anticipated availability. (WSPA4)

Comment: ConocoPhillips is not confident that offsets with approved protocols will be available in 2013-2014 to substantially reduce the additional costs to refiners imposed by the 10 percent reduction in allowances. ARB has maintained its ability to invalidate offset credits after issuance. ARB has maintained that the Buyer shall bear the liability related to offset revocation. While ARB has tightened the statue of limitations to five years if a project undergoes a second verification after three years of issuance of the credits, this does not do enough to ensure a robust offset market that meets the cost containment function ARB initially intended. ConocoPhillips believes that ARB's ability to invalidate issued credits and require the Buyer to replace the credit—in effect making the Buyer "pay twice"—will have devastating impacts on the offset market. Covered entities may choose to forego the offset market due to the inability to clearly identify and mitigate the risks associated with offset revocation. In Appendix A of ARB's Second 15-Day Cap-and-Trade Regulatory Text, ARB makes assumptions that are based on "maximum usage of offsets." This "maximum usage of offsets" will be completely undermined if Buyer's Liability remains a part of the cap-and-trade program. With the inability to identify and mitigate risks, covered entities will be reluctant to utilize and maximize their potential usage of offsets. Because of this reluctance by covered entities, offset developers will not be able to ensure demand for projects thus making financing of projects infeasible. This spiral will significantly retard the offset market and make the "maximum usage of offsets" scenarios which ARB identified infeasible. ConocoPhillips supports the proposal submitted by the International Emissions Trading Association (IETA), which involves a Compliance Buffer Account funded by a hold back of a certain percentage of credits from each offset project. ARB should also hold the responsible parties liable for making the system whole in the case of fraud or error. The IETA proposal, which is very widely supported by market participants including WSPA, would allow covered entities to address risk associated with offsets and ultimately reduce costs related to compliance. (CONOCO3)

Comment: Offsets represent an important cost containment tool for many food processors and producers and should the economy ever rebound, offsets will be vital to keeping the cost of allowances from skyrocketing as industries begin to ramp up production to meet demand. CLFP has recommended that CARB not take a restrictive approach to the use of emission offsets by cap-and-trade program participants such as limiting the number or percentage of offsets that can be used; the geographic location of offsets; or the types of offsets that would be eligible. Allowing the use and availability of a large quantity of offsets from the very beginning of the program will be crucial to the program's success. Policies that increase the likelihood of an inadequate supply of offsets and the inability to link to other cap and trade program will greatly decrease the potential for a cost effective California program. CLFP recommends that CARB instead focus on the quality of offsets; that they meet the requirements of being real, additional, quantifiable, verifiable, and permanent. As long as offsets meet that rigorous standard then their use by regulated entities should not be limited for compliance purposes. CLFP recommends that the proposed 8 percent level be established as a floor, and that additional offsets be allowed as necessary to maintain costs of the program within acceptable limits. For the same reason, we also recommend that the regulation not impose geographic limitations at this time. (CALFP4)

> **Response:** We did not increase the amount of offsets allowed to be used in the program. The program imposes a limit on the amount of offsets that an individual covered entity can use for compliance. All offsets used for compliance are real reductions, albeit outside the cap. Allowing a limited number of offsets into the program provides cost-containment benefits and ensures that some GHG emissions reductions occur within the sectors covered by the cap-and-trade program. This limit will be enforced through a limit on the use of offsets by an individual entity equal to eight percent of its compliance obligation. Combined with the Allowance Price Containment Reserve, this limit ensures that reductions from the program come from sources covered by the program at expected allowance prices, while use of the reserve will relax that constraint if prices rise.

Carry Over of Offset Limit

M-3. (multiple comments)
Comment: In an effort to provide flexibility and reduce compliance costs to regulated entities, companies should be allowed the flexibility of banking unused offsets on a year-to-year basis. Another mechanism that should be available to regulated entities is the ability to trade the balance of their remaining offsets to another company. (CALFP4)

Comment: The offset quantitative usage limit of 8 percent (section 95854) should be applied to the full duration of the proposed cap-and-trade program (i.e., 2013-2020) and not to each multi-year compliance period (i.e., 2013-2014, 2015-2017, and 2018-2020). (OFFSETSWG4)

Comment: Should California continue to have a quantitative usage limit, IETA continues to recommend that the usage limit apply to an entity's compliance requirement over the program's entire timeframe, currently out to 2020. Currently the usage limit expires with the end of each compliance period and unused capacity cannot be carried over to the next period. To the extent that a compliance entity does not fully utilize its quantitative offset limit, the absolute number of "unused" offset credits would be calculated and carried over to the entity's next compliance period. So, assuming the 8 percent rule applies, in the subsequent compliance period, a compliance entity's ability to use offset credits would equal 8 percent of "new" emissions during the compliance period, plus the absolute number of unused "carryover" credits from the prior period. Similarly, in all subsequent compliance periods, actual offset credits used would be subtracted from the "theoretical" offset credits allowed, for each entity, and that new absolute number would be the "carryover" for the next period, and so on, in perpetuity—so if the program were to carry on beyond 2020, unused offsets' compliance potential would not be foregone forever. Should the quantitative usage limit remain in place, IETA strongly recommends the inclusion of an administratively fair "carryover" by entity to the next compliance period provision for the full length of the program—eight years or from 2013 to 2020. (IETA4)

Comment: SCE continues to be concerned about offset supplies in the first two compliance periods. While the new shorter offset invalidation period will certainly help ensure a fungible market of high-quality offsets, any potential for invalidation may have the unintended effect of delaying the entry of offsets to market until they no longer have any risk of invalidation. Under the current rules, this time period is between three to five years. Accordingly, supply may be shifted from the first compliance periods—where it is already tight—to the later years of the program. Given the regulatory interest in maintaining a secondary invalidation option, it is critical that ARB establish regulations that recognize and address this potential delay. As the current offset use limit is applied to each discrete compliance period, such a limited supply could prevent compliance entities from using offsets toward the full 8 percent of emissions reductions authorized in the regulation. This will significantly limit opportunities for cost containment. To address this problem, SCE again suggests two specific modifications to the offset provisions. First, regulated entities should have the flexibility to use offsets up to 8 percent of reported emissions over the entire eight years of the cap-and-trade program. There is no environmental reason, nor any environmental benefit, to applying the 8 percent limit to discrete compliance periods. The global, long-term nature of climate change means that limiting the share of offsets within a particular compliance period is not environmentally relevant. As projects are gradually implemented under the four approved offset protocols, an increase in offset supply will likely come in the later years of the cap-and-trade program. To take advantage of this future expansion in supply, ARB should allow covered entities the flexibility to use offsets up to 8 percent of all reported emissions up to the time of offset submission. In doing so, ARB would be assured that the use of offsets would never exceed 8 percent of the entity's compliance obligation while affording flexibility to minimize the cost of compliance over the entire term of the cap-and-trade program. Modify section 95854 as follows:

> (a) Compliance instruments identified in section 95820(b) and sections 95821 (b), (c), and (d) are subject to a quantitative usage limit when used to meet a compliance obligation.
> (b) The total number of compliance instruments identified in section 95854(a) that each covered entity may surrender to fulfill the entity's compliance obligation ~~for a compliance period~~ must conform to the following limit:

Oo/S must be less than or equal to Lo

In which:

Oo = Total number of compliance instruments identified in section 95854(a) submitted since January 1, 2013 to fulfill the entity's total compliance obligation ~~for the compliance period~~ through the current compliance year.
S = Covered entity's total compliance obligation beginning January 1, 2013 through the current compliance year.
Lo = Quantitative usage limit on compliance instruments identified in section 95854(as), set at 0.08. (SCE4)

Comment: In order to promote lower cost compliance and market efficiency, CARB should allow facilities to carry forward and trade unused offset capacity. Facilities and market participants have expressed concern that they cannot bank unutilized offset compliance requirements for use between compliance periods. As the rules are currently drafted, for example, a facility uses offsets to satisfy only 6 percent of their annual compliance obligation in the first compliance period, cannot bank the remaining 2 percent for use in the second and third compliance periods, or trade the remaining amount to other facilities. As a means to reduce compliance costs and provide flexibility, sources should be given the ability to carry forward and trade unused offset capacity. (BGCEBS)

Comment: As long as ARB has rules in place to ensure that offset credits are high quality, there is no reason to implement artificial limits on their usage. ARB could be more encouraging investment in projects and could be more supportive during the long time horizon required for planning and investing in projects. Limits on the use of offsets will serve to inhibit investment and create uncertainty regarding the monetization of the carbon reduction portion of the projects. If ARB believes that a limit is needed on the use of offsets, the Trust recommends that ARB extend the time period for the quantitative limit to the full length of the program (from 2013-2020). This allows a maximum number of years for a compliance entity to invest in projects, or purchase credits in the market, in an efficient and cost effective manner. This is especially important because it is most efficient for projects to execute a single emission reduction purchase agreement for all credits. It is also more efficient for the compliance buyer to implement long-term contracts and they are involved in the projects for a longer period of time if they have flexibility to use offsets across all compliance periods rather than to meet obligations of a single compliance period. (TCT2)

Response: The regulation requires that offsets account for no more than eight percent of an individual entity's emissions over a three-year period. We did not allow the carryover of unused offsets within this time frame, to ensure that emission reductions are being achieved by capped sources throughout the life of the program. Keeping it to the compliance period allows some flexibility by giving three years to total emissions, but still requires that emission reductions are coming from within capped sectors in all years of the program.

Sector-Based Credits Limit

M-4. Comment: To ensure adequate supply of offsets is available, the Council encourages ARB to revise section 95854(c) to allow a complying entity to use up to 50 percent sector-based offsets toward the quantitative offset limit in the second compliance period. The limit as written would likely put further restrictions on the use of offsets, compounding shortages that many analysts predict will occur, particularly in the later years of the program. (BCFSE2)

> **Response:** We did not make this change. In the first 15-day changes to the regulation, the language was inadvertently changed so that the higher threshold applied to the second and third compliance periods. This was an error. In the second 15-day changes, we have reverted to the provisions in the originally proposed regulation, in which the higher threshold only applies to the third compliance period.

Ensuring Offset Quality and Criteria of AB 32

M-5. Comment: As we have stated in our previous comment letters, the establishment of specific, standardized, quantitative criteria to be applied in the review of compliance offset protocols is critical to providing clarity, transparency, and consistency in offset protocols and the offset credits they generate. The Cap-and-Trade regulation should identify explicit determinations, based on standardized criteria, that ARB will apply in their evaluation of all offset protocols. For example, the regulation should require specific determination of the risk of non-additionality, reversal, and leakage associated with an offset protocol, based on a quantitative analysis with explicit standards. This determination should be provided in the context of the volume of offset credits an offset protocol is expected to generate, and also should include a comparison of these factors among project types within an offset protocol and among offset protocols. To offer a specific example taken from Section 95792: "To be approved by the Board, a Compliance Offset Protocol must . . . (6) Ensure GHG emission reductions and GHG removal enhancements are permanent." This critical requirement is presented in the regulation here, and only here, as a general finding made by ARB upon adoption of an offset protocol. The permanence of GHG reductions, and the board's understanding of the risks associated with the protocol, would be much better assured if this provision required ARB to make a specific determination of the permanence of the credits provided by the protocol, based on a quantitative analysis of the persistence of the associated reductions, risk of reversals, and a comparison of those risks among different offset project types. (CBD5)

> **Response:** We believe that the Compliance Offset Protocols, in conjunction with all of the strict and thorough requirements in the regulation regarding offsets, meet the requirements of AB 32. The Compliance Offset Protocols adopted

under the cap-and-trade regulation have been established with multiple levels of review, use conservative methods to account for uncertainty and emissions leakage, and establish the additionality of offset projects in setting project baselines. The regulation requires that all Compliance Offset Protocols address activity-shifting and market-shifting leakage. Each protocol incorporated by reference, including the forest protocol, accounts for leakage in the quantification of the reductions or removals achieved by the offset projects. In addition, when uncertainty exists in quantifying GHG reductions, ARB will only issue offset credits when there is a high level of confidence that reductions actually occurred. The regulation employs a principle of conservativeness in the quantification of emissions reductions. This method will ensure that the accounting will underestimate, rather than overestimate, any reductions when there is a high level of uncertainty.

We agree that offset protocols must ensure environmental integrity. Generally, we do not include implementation-related procedures in our regulations. As directed in Board Resolution 11-32, we will develop guidance documents related to the protocol approval process in 2012. In addition, all offset protocols used in the compliance program must be adopted by the Board after undergoing a full regulatory process, including an ARB stakeholder process, in accordance with the Administrative Procedure Act, and an environmental review. ARB plans to look at further offset protocols for potential inclusion in the cap-and-trade program beginning in 2012. The details surrounding any new offset project types for which ARB adopts an offset protocol will be addressed during that specific rulemaking, and modification will be made to the cap-and-trade regulation as needed.

M-6. Comment: As stated in our previous comment letters, ARB's proposed regulation similarly lacks standards and safeguards necessary to ensure that offsets are "additional" as required by AB 32. AB 32 requires ARB to ensure that emissions reductions achieved through a market-based compliance program are "in addition to any greenhouse gas emission reduction otherwise required by law or regulation, and any other greenhouse gas emission reduction that otherwise would occur." Health & Safety Code section 38562(d)(2) (emphasis added). As a threshold matter, the additionality requirements of proposed section 95973 are not entirely consistent with the statutory language. Under the proposed regulation, "[t]he activities that result in GHG reductions and GHG removal enhancements, are not required by law, regulation, or any legally binding mandate applicable in the offset project's jurisdiction, and would not otherwise occur in a conservative business-as-usual scenario." Section 95973(a)(2)(A) (emphasis added); see also section 95802(a)(3). The proposed regulation does not otherwise define "business-as-usual scenario," and the conservativeness principle—while certainly appropriate in this context—does not fully ensure that all reductions are in addition to those "that otherwise would occur," as AB 32 requires. (CBD5)

Response: We disagree with the statements about additionality. We believe that the Compliance Offset Protocols, in conjunction with all of the strict and thorough requirements in the regulation regarding offsets, meet the requirements of AB 32. The Compliance Offset Protocols adopted under the cap-and-trade regulation have been established with multiple levels of review, use conservative methods to account for uncertainty and emissions leakage, and establish the additionality of offset projects in setting project baselines.

The regulation does define "Business-as-Usual Scenario" in section 95802(a)(36), and "Conservative" is defined in section 95802(a)(60). We believe the definitions of these terms ensure that the requirements of AB 32 will be met for the adoption of protocols and for ensuring additionality.

M-7. Comment: We appreciate that ARB may have intended to address this shortcoming of the regulation in part through section 95972(a)(9), which as proposed in this 15-day notice requires Compliance Offset Protocols to: "Establish the eligibility and additionality of projects using standard criteria, and quantify GHG reductions and GHG removal enhancements using standardized baseline assumptions, emission factors, and monitoring methods." However, "standard criteria" in this provision is left undefined; again, the regulation provides no assurance that credits created under these protocols will be additional as required by AB 32. Again, a more meaningful provision would require ARB to make a specific determination of the risk of non-additionality, reversal, and fraud associated with an offset protocol, based on a quantitative analysis with explicit standards, and provided in the context of the volume of offset credits an offset protocol is expected to generate and a comparison of these factors among project types within an offset protocol and among offset protocols. In addition, this provision should include the components of additionality set forth in subsection 95973(a)(2)(A) or be cross-referenced to that subsection. (CBD5)

Response: We agree that offset protocols must ensure that GHG reductions and the GHG removal enhancements resulting from them meet the criteria listed by the commenters. To ensure that GHG reductions and GHG removal enhancements credited as offsets are real, the regulation requires that all Compliance Offset Protocols address activity-shifting and market-shifting leakage. Each protocol incorporated by reference accounts for leakage in the quantification of the reductions or removals achieved by the offset projects. In addition, when uncertainty exists in quantifying GHG reductions, ARB will only issue offset credits when there is a high level of confidence that reductions actually occurred. The regulation employs a principle of conservativeness in the quantification of emissions reductions. This method will ensure that the accounting will underestimate, rather than overestimate, any reductions when there is a high level of uncertainty.

Generally, we do not include implementation-related procedures in our regulations. As directed in Board Resolution 11-32, we will develop guidance documents related to the protocol approval process in 2012. In addition, all offset protocols used in the compliance program must be adopted by the Board after undergoing a full regulatory process, including an ARB stakeholder process, in accordance with the Administrative Procedure Act, and an environmental review. ARB plans to look at further offset protocols for potential inclusion in the cap-and-trade program beginning in 2012. The details surrounding any new offset project types for which ARB adopts an offset protocol will be addressed during that specific rulemaking, and modification will be made to the cap-and-trade regulation as needed.

We believe that the requirements for offset protocols in section 95972 and our Compliance Offset Protocol stakeholder processes will ensure that this is met.

M-8. Comment: The proposed modifications would change Section 95972(a)(4) to read as follows: "[To be approved by the Board, a Compliance Offset Protocol must] . . . [a]ccount for activity-shifting leakage and market-shifting leakage for the offset project type, unless the Compliance Offset Protocol stipulates eligibility conditions for use of the Compliance Offset Protocol that eliminate the risk of activity-shifting and/or market-shifting leakage." The addition of this exception appears targeted toward the Compliance Offset Protocol U.S. Forest Projects ("Forest Offset Protocol"), which contains very high risks of leakage, especially when compared to other protocols. To be clear, the Forest Offset Protocol does not—and cannot—"eliminate" the risk of leakage. At the very least, the regulation should require a specific quantitative determination of the risk of leakage associated with an offset protocol, provided in the context of the volume of offset credits an offset protocol is expected to generate, and a comparison of these factors among project types within an offset protocol and among offset protocols. (CBD5)

Response: This provision is not targeted to the forest protocol. Instead, the provision was added to accommodate those project types that may be able to completely eliminate the risk of leakage, which may be the case in some agricultural project types. If a protocol can completely eliminate the risk of leakage, it will not need to account for it in the quantification of emissions reductions. This provision is not intended to allow a less rigorous interpretation.

M-9. (multiple comments)
Comment: According to the AB 32 statute, offsets must be additional to any greenhouse gas emission reduction that would otherwise occur. It is this additionality that is so difficult to determine. As such, the use of offsets as a compliance instrument, *not* inherent to a cap-and-trade system, presents substantial risks of not genuinely achieving the emissions reductions called for in AB 32. When offsets credits are generated by business-as-usual projects that were going forward regardless of the offsets payments, the companies under the cap are able to emit more than the cap, but equivalent additional emissions aren't reduced elsewhere. The companies are simply paying project owners outside of the cap to do what they were doing anyway. The cap-and-trade program would therefore be effectively weakened by the number of non-additional business-as-usual offset credits allowed for compliance. We strongly recommend that the regulation include a requirement that an additionality assessment

be conducted of new protocols prior to adoption, and periodically on all existing protocols.

- These additionality assessments should be made publicly available.
- Each additionality assessment should evaluate whether the protocol is likely to meet CARB's requirements that all credits are real and additional using the following evaluation criteria (in addition to other criteria already in the draft regulation):
  - There is a very high degree of confidence that the total number of credits generated by projects under the protocol will not exceed the total amount of reductions enabled by that protocol in addition to what would have happened without that protocol,
  - The project types that qualify under the protocol, absent being eligible as part of the compliance offset protocol, are not likely to be pursued, are likely to result in reductions that are negligible in number, or would likely have been pursued at significantly lower rates; and
  - The protocol conservatively accounts for uncertainty in quantification factors for the offset project type.
- In addition, periodic reviews of existing protocols should assess the influence that the protocol has already had on new project development.

Moreover, a review should be triggered when any of the following would result in substantial changes in the estimation of emissions reductions from offset projects:

- Research advancements on quantifying emissions reductions from protocol project types;
- Updates to related registry protocols that lead to more accurate or conservative measurement of emissions reductions;
- Significant changes in market conditions affecting the rate at which projects would be developed without the offset protocol; or
- Changes in the baseline. (UCS9)

Comment: Further enhancements to verifier and registry oversight are needed to ensure that offset project developers do not over-estimate the reductions from their projects. Modify section 95971 as follows:

<u>(c) A review shall be triggered when any of the following would result in substantial changes in the estimation of emissions reductions from offset projects:</u>

<u>(1) Research advancements on quantifying emissions reductions from protocol project types;</u>
<u>(2) Updates to related registry protocols that lead to more accurate or conservative measurement of emissions reductions;</u>
<u>(3) Significant changes in market conditions affecting the rate at which projects would be developed without the offset protocol; or</u>
<u>(4) Changes in the baseline.</u> (UCS8)

Comment: We would like to reiterate the importance of providing further clarification regarding how new and existing protocols will be evaluated to ensure that the credits they will generate will represent real and additional reductions. The biggest challenge in running an offsets program is ensuring that the credits generated are real and additional since it is so difficult to determine what might or might not have occurred in the absence of the protocol. This requires performing an additionality analysis on all new protocols when they are considered for adoption, and periodically assessing existing protocols. An additionality analysis assesses the projects that are likely to be credited under the protocol and evaluates whether there is a high level of confidence that the protocol will not create more credits in total than the reductions the protocol causes (above what would have happened in the absence of that protocol). In addition, a protocol review also involves an analysis of the additionality of the credits that have been issued under the protocol in the prior period. Since this is essential to running an offsets program, we request that such an analysis be made explicit in the regulation, or perhaps for some provisions, in a supplemental document. These additionality assessments should be made publicly available. (UCS8)

> **Response:** We believe that the Compliance Offset Protocols, in conjunction with all of the strict and thorough requirements in the regulation regarding offsets, meet the requirements of AB 32. The Compliance Offset Protocols adopted under the cap-and-trade regulation have been established with multiple levels of review, use conservative methods to account for uncertainty and emissions leakage, and establish the additionality of offset projects in setting project baselines.
>
> Generally, we do not include implementation-related procedures in our regulations. As directed in Board Resolution 11-32, we will develop guidance documents related to the protocol approval process in 2012. In addition, all offset protocols used in the compliance program must be adopted by the Board after undergoing a full regulatory process, including an ARB stakeholder process, in accordance with the Administrative Procedure Act, and an environmental review. ARB plans to look at further offset protocols for potential inclusion in the cap-and-trade program beginning in 2012. The details surrounding any new offset project types for which ARB adopts an offset protocol will be addressed during that specific rulemaking, and modification will be made to the cap-and-trade regulation as needed.

M-10. Comment: CARB should evaluate the enforceability of offsets. Can CARB oversee these offsets even for 100 years? What about CARB's intention to link to the Western Climate Initiative and to other countries? Will CARB be able to enforce out of state and international offsets for even 50 years, if at all? Will CARB have the ability to enforce offsets if our relations with another country turn sour? In decades, conditions can change drastically, rendering the offsets unenforceable. It is patently obvious that instead of providing this major offsets program, that allows polluters to avoid 80 percent of the reduction aims of this program, CARB would have a vastly more enforceable program if it performed its normal function of regulating the polluters right in California. (CBE3)

Response: The role of offsets is to provide cost containment for the market program. Covered entities will have to weigh the costs of purchasing offsets for meeting a near-term compliance obligation versus investing in onsite reductions that would provide emissions reductions throughout the three compliance periods. We believe the current regulation is enforceable. There are no international offsets included in the cap-and-trade regulation. The issues raised on this point will be part of a separate, future rulemaking, where we will have to evaluate and ensure that any offsets, including international offsets, meet the AB 32 criteria. Also see the response to Comment M-13 in this chapter.

M-11. Comment: We are submitting the following press release at: http://yosemite.epa.gov/opa/admpress.nsf/0/0fdbab7c7ab964d28525791700614ae0?OpenDocument to document the pressures that dairies are under to improve manure management and insure that they do not impact other local agriculture and waterways. As this press release provides additional evidence that it is not possible to discern whether a dairy or other livestock farm decides to use an anaerobic digester because of the offset program/payment and when this decision would have occurred otherwise, in the absence of the offset program, as a result of other pressures, including the threat of regulatory enforcement against discharges and potential nuisance and tort actions by neighboring landowners and communities. As noted in our prior comments (August 2008, December 13, 2010, July 27, 2011, and August 10, 2011) offset credits that lack integrity and are not additional will undermine the integrity of the entire AB 32 program and its accounting of reductions, and is contrary to the requirements of AB 32. (WILLIAMSZ4)

Response: Currently, there are no regulations or proposed regulations to mandate the implementation of anaerobic digesters. The implementation of anaerobic digesters is also not something currently considered common practice. Regulatory additionality is assessed based on the regulatory environment at the time of the offset project's implementation. Additionality is not intended to look at what types of regulations could potentially be implemented in the future. The purpose of the offsets program is to incent actions to reduce GHG emissions for those activities that are not already required or being implemented as part of current practices. ARB will periodically assess all offset project types to determine if they are still additional. If a new law is passed or an activity has become common practice, no new offset projects would be able to be implemented. As such, it is not practical or technically accurate to consider an activity unadditional because there may be some unforeseen regulations that could be implemented in the future.

M-12. Comment: Several important additions and clarifications were incorporated into the regulation regarding periodic reviews of offsets protocols (95971(b)), and performance reviews of verifiers (95132(c)(2) and (4) of the MRR) and registries (95986(k)(5)(B)). We support and appreciate these changes, and believe these reviews are essential to ensuring that offsets credits generated under CARB's offsets program meet the criteria outlined in the regulation. Moreover, it is important for all involved to have a sense of certainty that these procedures will be implemented, and for those being evaluated to be made aware of review procedures they can expect. (UCS8)

Response: Thank you for your support. We plan to develop guidance documents related to the protocol approval process in 2012. We also have included provisions in the regulation for performance reviews in the regulation, as mentioned by the commenters.

M-13. Comment: California is in a position to create a model for other carbon offsets programs. The track record of offset programs has been poor with regard to the quality of the credits for GHGs or for other gases. While the proposed regulation is structured to potentially have better results than other offsets programs, additional protections and oversight provisions are still needed. Given that the total number of offsets allowed for compliance under California's cap-and-trade program cumulatively through 2020 equals approximately 80 percent of cumulative emission reductions required under the program, the integrity of those offsets is critical to the effectiveness of the market-based program overall. (UCS8)

Response: We believe offsets are real GHG reductions, albeit from outside the cap. We also believe that the Compliance Offset Protocols, in conjunction with all of the strict and thorough requirements in the regulation regarding offsets, meet the requirements of AB 32. The Compliance Offset Protocols adopted under the cap-and-trade regulation have been established with multiple levels of review, use conservative methods to account for uncertainty and emissions leakage, and establish the additionality of offset projects in setting project baselines. To assure offset quality, the program includes rigorous oversight and audit procedures for all ARB-accredited offset verifiers, offset project developers, and offset project registries. In addition, the registry system for compliance instruments is being designed to provide strong enforcement capabilities, including mechanisms to prevent double-counting, public disclosure requirements, and methods to clearly define ownership.

The regulation proposes a robust monitoring program for offset projects—both the verification that the offsets are real, additional, and enforceable, and that Offset Project Operators, verifiers, and Offset Project Registries are operating according to regulatory requirements. In addition to the ARB audits, Offset Project Registries are required to conduct oversight of their registry program and randomly audit verifications to ensure that our regulatory requirements are being met by Offset Project Operators and verification bodies. We will provide rigorous oversight of our approved Offset Project Registries. Each year, the Offset Project Registries will provide us with a report providing basic information related to any offset project listed using a Compliance Offset Protocol and any findings related to verification audits. We will require Offset Project Registries to provide any information related to an offset project when requested by us as part of the registry's oversight of their program for Offset Project Registry. During the course of an offset project, the Offset Project Registry will track any guidance or information provided to an Offset Project Operator related to a compliance offset project and report this information monthly to ARB. This approach will ensure that we understand any issues or concerns related to the registry's compliance offset program as Offset Project Operators implement the actual offset projects.

M-14. Comment: A slight change in section 95971(b) may better reflect the intension of this revision. The reviews rather than the revisions should be periodic; revisions should be made as needed. Modify section 95971(b) as follows:

(b) All Compliance Offset Protocols shall be periodically reviewed and ~~periodically~~ revised if needed. (UCS8)

Response: We did not make this change. We believe the current language shows the correct intent.

M-15. (multiple comments)
Comment: Where there is systematic uncertainty (defined here as when an incorrect value would result in the incorrect estimate of the emissions reduced by all projects of a certain type in the same direction (high or low)), calculation methods should be conservative. This is necessary to ensure that California meets its emissions reduction targets. Reductions under an offsets program are inherently less certain than similar reductions under a cap because an offsets program measures emissions reductions against a counterfactual scenario. So that CARB's offsets program does not allow fairly certain reductions under the cap to be replaced with less certain, and therefore poorer quality, reductions outside of the cap, systematic uncertainty must be addressed conservatively. Modify section 95972(a)(5) as follows:

(5) Conservatively account for uncertainty in quantification factors for the offset project type. (UCS8)

Comment: A protocol should not over-credit emissions reductions. It is impossible to assure that every single credit represents a real and additional reduction. But it is possible to have a high degree of confidence that, in total, the protocol does not generate more credits than the total reductions it enables (causes). We recommend adding the following statement. This statement is at the heart of what an additionality assessment of a protocol would assess and is meant to provide an operational definition of the terms "real" and "additional." Modify section 95972(a) as follows:

(11) Ensure, with a very high degree of confidence, that the total number of credits generated by projects under the protocol will not exceed the total amount of reductions enabled by that protocol in addition to what would have happened without that protocol. (UCS8)

Comment: By statute, all offsets credits used for compliance under AB 32 must represent real and additional reductions. By definition, if reductions are additional, one of the following three options must be met: the reductions would not have happened otherwise, or the reductions that would have happened otherwise are negligible in number, or the reductions that would have happened otherwise are very small in number compared to the additional reductions caused by the protocol. The only other possibility is that the reductions that would have happened without the protocol is not small compared to the additional reductions, in which case the protocol does not meet ARB requirements. We therefore believe that the following requirement is necessary for the additionality requirement to be met, and should be made explicit in the regulation to avoid any potential misunderstanding. Modify section 95972(a) as follows:

> (12) Ensure the project types that qualify under the protocol, absent being eligible as part of the compliance offset protocol, are not likely to be pursued, are likely to result in reductions that are negligible in number, or would likely have been pursued at significantly lower rates; (UCS8)
>
> **Response:** We agree that offset protocols must ensure that GHG reductions and GHG removal enhancements resulting from them meet the criteria listed by the commenters. We did not make any changes based on the comment because we believe that the requirements for offset protocols in section 95972, along with our Compliance Offset Protocol stakeholder processes, will ensure that these criteria are met.

Offset Supply and Additional Offset Protocols

M-16. (multiple comments)
Comment: Carbon offsets from non-capped sectors in California's cap and trade program will be an essential cost containment mechanism available to covered entities. They will provide lower-cost emission reductions, particularly if purchased and banked early in the program before escalating marginal abatement costs. The quality and the integrity of the carbon offset are critical to safeguard in the design of the offsets program, and because of this, quality and integrity rather than project type, should be the primary concern of the ARB. Although the latest round of proposed rule changes do not include additional early action protocols, ARB staff has indicated their intention to consider offset protocols relating to the replacement of high-bleed pneumatic valves and changes in agricultural processes. Evolution Markets applauds ARB's efforts to expand its early action protocols, and encourages the Board to adopt these protocols as expeditiously as possible. In addition, the ARB should publish a list of "priority" protocols for adoption by the Board next year. Evolution Markets believes, however, that the potential volume from these protocols will continue to be insufficient to meet early demand for offsets. Therefore, Evolution Markets recommends ARB consider additional high-volume protocols for adoption in the early action program. (EVMKTS3)

Comment: ARB has made no modifications to the draft regulations regarding the list four CAR protocols used to classify compliance-eligible offsets and those eligible to receive early action credit. IETA commends ARB for providing some guidance on three additional protocols, and also providing notice that it will suggest further protocols for review at the Board meeting in October. IETA has concerns that there will be offset supply shortages if the current project types are not increased and, in the short-term, about the infrastructure being in place to enable offsets from early-action projects to come to market as quickly as possible. IETA also has concerns about the transparency with which new offset protocols are assessed and announced. Without additional protocols, a timeline for infrastructure development and a more transparent process for new protocols being considered the market will not be able to provide sufficient supply when needed to effectively mitigate costs to California consumers. (IETA4)

Comment: Emission reductions from all qualified existing CAR projects should be brought into the compliance system and become compliance eligible. In addition, ARB should consider recognizing protocols from other high-quality carbon project standards organizations, such as the Verified Carbon Standard, the American Carbon Registry and the Gold Standard. Recognizing existing projects will help to create a greater initial supply of offset credits for the market. (IETA4)

Comment: In the first compliance period, the supply of offsets will very likely be too limited to cover the eight percent of emissions as allowed for under ARB's proposal. The BCSE was very encouraged to hear ARB staff state during the August 24, 2011 public meeting the consideration of three specific additional offset protocols, including protocols for Conversion of Pneumatic Controllers, N_2O Reductions from Changes in Fertilizer Management, and Emissions Reductions in Rice Management Systems. The first two of these are protocols of BCSE member Winrock International's American Carbon Registry (ACR), and the third is currently going through the ACR approval process for publication this fall. To ensure adequate offset supply and cost containment for the larger cap-and-trade program, the BCSE encourages ARB to work quickly to approve these and other protocols. (BCFSE2)

Comment: We encourage the Board to adopt additional high-quality, publicly-developed, standardized offset protocols that have been tested and improved through real-world use such as those employed by the Climate Action Reserve. (CAR5)

Comment: Offsets have been referred to as a small piece of a much larger program. While that may be accurate from a volume perspective, the pricing impact of inadequate offset supply as a cost containment measure cannot be understated. In addition to the three protocols that ARB indicated they would consider at the August 24, 2011 Board meeting (American Carbon Registry (ACR) pneumatics valves, ACR nitrogen fertilizer management, and rice cultivation) we encourage ARB to consider additional protocols which have significant issued credits to date that could address the immediate need for offsets in the first compliance period. The ACR nitrogen fertilizer management protocol has no issued tons to date and the rice cultivation protocol(s) have yet to be finalized. Offset projects take many months to develop and contract. Given the risk and uncertainty, it is unlikely that there will be substantial investment in the three proposed project types unless and until the Board approves these additional protocols. Additionally, the one year delay of the program compliance obligation combined with the uncertainty regarding both invalidation liability and Early Action offset transition to ARB offset process and costs have discouraged investment in the four approved protocols sufficient to meet offset demand in the first compliance period. As such, we recommend evaluating additional Early Action protocols that, in addition to being real, additional, quantifiable, permanent, verifiable, and enforceable, have the potential to add immediate supply to the program. Specifically, we encourage ARB to consider the Early Action CAR US Landfill Gas Protocol (4.9 $MMTCO_2e$ issued (net retirements)) and VCS Coal Mine Methane Protocol (1.2 $MMTCO_2e$ issued (net retirements)). Regarding Early Action CAR US Landfill Gas in particular, we support that statements made by PG&E and contend that Early Action ARB offset credits should be issued to US landfill operators that voluntarily reduced emissions in advance of California's Landfill Methane Control Measure that was approved on June 17, 2010 but allows landfills 18 months to install a collection system. (CE2CC2)

Comment: One of the biggest issues yet to be addressed by ARB is the introduction of additional offset compliance protocols. While CERP recognizes that the 15-day rulemakings are not the appropriate place to introduce new protocols, CERP urges ARB to move forward with new protocols as quickly as possible in order to offer the market certainty concerning what project types will be included. Offset projects take significant time to implement, and thus there will be significant lag time after new protocols are accepted by ARB before projects can be expected to be introduced into the market. (CERP5)

Comment: CERP requests that ARB move expeditiously toward introducing new offset protocols with the ability to contribute significant supply to the compliance market. (CERP5)

Comment: A robust supply of offsets is required in order to reduce program costs. Therefore, a consideration of offset protocols, outside the four currently under consideration, is encouraged. (CALCHAMBER4)

Comment: The protocols in this second 15-day administrative rulemaking are being revised in the right direction, but the revisions do not go far enough. Two key actions are necessary to support the development of a robust offset market that will lower compliance costs and ultimately reduce the program's impact on the California economy. First, we strongly encourage ARB to continue evaluating and adopting additional protocols for compliance under AB 32. As more protocols are adopted, the supply of high quality offsets will increase and will drive down overall offset and compliance costs to the market. Second, ARB quickly needs to establish a process and requirements for entities to convert early action offsets into compliance-grade offsets. The sooner this happens, the sooner market participants will make investments in early action offsets. This will jump start the establishment of a robust offset supply that will be able to meet the demand, especially in later compliance periods. (CHEVRON4)

Comment: There is a great need for ARB to provide more clarity regarding additional project types that may become eligible for offset credit. Developing offsets is a long and complex process that requires significant investment. It can take years for new projects to become market ready. Considering the demand for offsets will only rise over time, giving project investors as much foresight as possible will help ensure adequate supply is available. (IETA4)

Comment: Because offsets are critical for cost containment, SCE continues to strongly support their use in the cap-and-trade program. SCE offers four essential principles that ARB staff should consider when reviewing and revising the offset rules:

- Robust supply. A strong supply of offsets, especially in the first years of the cap-and-trade program, will ensure that compliance entities are able to maximize their use of these important compliance instruments.
- Cost-effectiveness. High-quality but inexpensive offsets will allow compliance entities to limit their compliance costs, furthering the goals of the cap-and-trade program without unduly jeopardizing California economic vibrancy.
- High-quality offsets. High-quality offsets, mandatory for environmental integrity, will also ensure that the risk of invalidation does not overly constrict supply or raise prices in the offset market.
- Offset market liquidity. A liquid market with fungible products will provide an efficient way for the regulated community to access these high-quality and cost-effective offsets. (SCE4)

Comment: SCE strongly urges ARB to work towards developing and approving additional offset protocols. SCE supports ARB's consideration of new protocols addressing replacement of high bleed pneumatic values and improved agricultural practices, as presented in a recent staff update on AB 32 climate change program activities. Given the lengthy timeframes for offset project development, implementation and verification, SCE urges ARB to expeditiously consider and obtain Board approval of these and other new protocols in early 2012. (SCE4)

Comment: The four compliance offset protocols included in this rulemaking specify, in general, that all eligible projects must be located within the United States. This requirement appears to be in conflict with the principle of reciprocity announced by the Western Climate Initiative (WCI), of which the State of California is a partner. Under that principle, offsets issued by one WCI Partner Jurisdiction will be recognized and accepted for compliance in all other Partner Jurisdictions. As the ARB protocols are currently written, it appears that a project following one of the ARB protocols, but undertaken in a Canadian Partner Jurisdiction, could not be issued compliance offset credits in California. Clarify the ARB offset protocol requirements to ensure that projects following those protocols but undertaken in jurisdictions with which California has linkages will be eligible for recognition in California. (VCSA2)

Comment: NextEra would like to strongly urge ARB to consider incorporating more offset protocols into the program. We understand that this requires additional rulemaking. ARB staff has indicated that rulemaking could potentially take place in 2012 to address this as well as other issues. NextEra would support that effort and be willing to participate in the process to assist ARB in reviewing protocols to ensure they meet the goals and requirements of AB32. We feel the availability of offset credits is critical to controlling the cost of allowances and the impact the cap and trade program will have on consumers. In addition, some projects result in the production of co-benefits to the public and the environment. We would ask that ARB staff seriously consider adding the following list of offset protocols to the regulation and also consider the following additions to existing protocols:

- Improved forestry management. Including protocols for specific geographic areas. Forestry practices vary depending on the location and species of trees
- Industrial gas abatement. Add N_2O and SF_6 to protocol for abatement of ozone depleting substances (ODS)
- Landfill gas. Projects outside of CA where regulations do not require controls.
- Coal mine methane abatement. Potential projects exist across WCI region.
- CO_2 sequestration (NEXTERAENERGY3)

Comment: TFI would like to commend ARB for its decision to evaluate agricultural protocols for compliance purposes as outlined in the August Board meeting presentation. Agricultural soil management accounted for over 200 million metric tonnes of carbon dioxide equivalent (CO_2e) and nitrous oxide emissions from nitric acid production accounted for over 21 million tonnes of CO_2e in California and the United States in 2009. There are numerous opportunities to reduce these GHG's in California and the United States that are real, measurable and verifiable with significant environmental benefits. (TFI2)

Comment: TFI recommends ARB review and adopt the existing CAR's Nitric Acid Production Protocol for compliance purposes during your protocol review in 2011/12. The nitric acid sector is currently at the forefront of environmental stewardship through the reduction of GHGs in commercial and organic fertilizer manufacturing. Nitric acid plants can be large GHG emitters through release of nitrous oxide (depending on the type of pollution abatement system historically implemented) in the production process. Fortunately, the development of the CAR Nitric Acid Production Project Protocol has allowed five projects to develop voluntarily that will generate 2 million offset credits per year this year and over 2.5 million offset credits by 2012. In addition, there are a number of other facilities planning additional projects using the CAR Nitric Acid Production protocol. It is important to note that the nitric acid industry participants can guarantee the offsets to the end buyer and are very comfortable with the requirements of section 95985—Invalidation of ARB Offset Credits. The offsets generated from N_2O destruction are the most verifiable offsets achievable. Currently there are two nitric acid facilities in California that supply the fertilizer production industry with feedstock to make nitrate based fertilizers. Preliminary discussions with ARB staff have highlighted early support for adoption of the protocol with potential changes to how production facilities would be included in the overall GHG capped sectors. TFI looks forward to engaging ARB on this issue in the future. (TFI2)

Comment: TFI is currently developing a new, comprehensive field protocol based on the "4R" nutrient stewardship system (using the right nutrient source at the right rate, right time and right place). This protocol should also be reviewed and adopted for compliance purposes to ensure the agriculture sector is working to develop long-term solutions to reduce sectoral GHG emissions. TFI's 4R protocol is aimed at reducing

GHG's from agricultural nutrient management (i.e. fertilizer field application) in a comprehensive, quantifiable and verifiable manner. TFI's process is aligned with both the Canadian and Iowa/Illinois Nitrous Oxide Emission Reduction Protocols and calls for stringent requirements to ensure the highest quality of offsets. Quality is maintained through detailed descriptions of growers' past and future activities and by utilizing an output-based approach and regional coefficients calculated via USDA GHG quantification methods and tools. The protocol was designed according to technical recommendations given by the Technical Working Group on Agricultural Greenhouse Gases (T-AGG). Finally, the protocol pledges to remain technology neutral, guaranteeing the acceptance of alternative approaches such as organic, dynamic or conventional application methods. A key additional benefit from TFI's 4R protocol is that it is focused on changing farmer behavior through the 4R stewardship education program. The protocol is being tested, through USDA grant funding, on Iowa/Illinois producers in corn-bean rotations. TFI is playing a leading role in development of the protocol using its expertise on serving on the USDA Agricultural Air Quality Task Force which provides recommendations on emerging regulatory issues related to agricultural air quality for USDA. TFI also serves on the board of the Conservation Technology Innovation Center, an organization devoted to educating and increasing uptake of nutrient and conservation based practices such as no-till and low-till systems including cover crops, buffer strips, and 4R nutrient management. In conclusion, the fertilizer industry is demonstrating strong leadership in environmental stewardship within the agricultural sector. The industry recognizes the potential impacts of improper nutrient management and is promoting uptake of 4R nutrient management and site-specific conservation practices. Accepting the proposed TFI 4R nutrient management protocol would be a win-win for both California's agricultural producers and regulated entities under AB 32. (TFI2)

> **Response:** These comments fall outside the scope of the second 15-day changes to the regulation; therefore, no further response is required. Responses to similar comments can be found in this category under the 45-day comment responses.

M-17. Comment: State officials must continue to consider how to practically link with external offset and allowance programs, including the Western Climate Initiative (WCI), the Regional Greenhouse Gas Initiative (RGGI), Clean Development Mechanism (CDM), and EU ETS. (IETA4)

> **Response:** This comment falls outside the scope of the second 15-day changes to the regulation; therefore, no further response is required. Responses to similar comments can be found in this category under the 45-day comment responses.

M-18. (multiple comments)
Comment: IETA recommends ARB establish an open and defined official path or mechanism through which offset project developers can propose new project types and

methodologies for consideration. At the moment, there is no formal path for introducing such methodologies and this would greatly streamline the process. (IETA4)

Comment: The modified draft rule provides no formal path for submitting methodologies for review, evaluation and approval by ARB. An open, transparent process for receiving, reviewing, evaluating and approving offset methodologies provided and/or developed by third parties is a necessary signal for the market to continue developing protocols (and projects) that will provide the offsets necessary for effective cost-abatement. ARB should establish an open and defined mechanism through which offset project developers can submit new project types and methodologies for consideration. VCSA suggests that ARB consider adopting a process similar to that employed by the Australian Department of Climate Change and Energy Efficiency for inviting parties to submit methodologies for review and approval under that country's forthcoming Carbon Farming Initiative. Details about that submission process can be found at http://www.climatechange.gov.au/government/initiatives/carbon-farming-initative/methodology-development/methodology-guidelines.aspx. (VCSA2)

Comment: Despite our earlier recommendations and similar recommendations provided by other parties, the proposed rule makes no provision for a defined mechanism by which ARB will receive and consider offset methodologies developed and/or presented by third parties for approval as compliance offset protocols and/or early action offset project protocols. We believe that the absence of a defined mechanism is not in the public interest, as it enables a closed non-transparent process that can result in unequal treatment being given to project and methodology developers seeking consideration by the Board. By limiting the opportunity for third parties to submit protocols for consideration, the absence of a defined submission mechanism does not serve ARB's own interest in executing the most administratively efficient program. Moreover, failing to provide clear guidance regarding the parameters that offset protocols must follow risks establishing a system that is inconsistent across project types. (VCSA2)

> **Response:** This comment falls outside the scope of the second 15-day changes to the regulation; therefore, no further response is required. Responses to similar comments can be found in this category under the 45-day comment responses.

Offset Project Registries

Registry Approval Process and Requirements

M-19. (multiple comments)
Comment: Given the central role that registries play in ensuring the environmental and financial integrity of an emissions reduction and trading program, it is important that the providers of registry services are themselves technically capable, financially sound, and managerially competent entities. VCSA believes that the requirements for Offset

Project Registries outlined in the proposed rule are not robust enough for purposes of establishing the sound, long-term functioning of the offsets program. For its own program, the VCSA requires its registry service providers to meet strict financial standing requirements (including, for example, more extensive insurance coverage than required by ARB and minimum net asset requirements), and have in place insolvency protections and conflict of interest policies (including prohibitions on proprietary trading of carbon instruments) that go beyond the requirements indicated in the modified draft rule. We suggest that ARB establish similar standards. Amend section 95986(c) to include requirements that Offset Project Registry applicants meet more robust financial standing standards similar to those established by VCSA for its registry service providers. Annex 1 to this letter provides a summary list of the requirements set out by the VCSA as part of the RFP issued for VCS registries. (VCSA2)

Comment: We would encourage the Board to continue to strengthen the offsets component of the Regulation by ensuring offset registries meet the highest possible standards. We believe that more can and should be done in this regard. In particular, the reserve encourages the Board to impose much stronger competency and conflict of interest requirements for offset registries. We would expect such requirements to, at a minimum, mirror or, more preferably, exceed those imposed on verification bodes since registries will serve as ARB's first point of contact and provide vital oversight of ARB's verification system. (CAR5)

> **Response:** The regulation requires that ARB will only approve registries that meet a high standard under the regulation. Once a registry is approved, it is subject to ARB's enforcement. We provide registries some flexibility in how they structure themselves to be responsive to offset project developer needs, and to ensure that the registry can provide the registry services at the level dictated in the regulation. The registry staff will be required to demonstrate practical knowledge of the protocols approved by the Board. The regulation contains requirements for regular information-sharing between the registries and ARB. The regulation allows for ARB to request information or discussions with registry staff at any point. As with many of ARB's regulations, compliance training will be available, and in this case required, to ensure that the highest qualified personnel are on staff at the registries.
>
> In addition, we made changes to the registry approval section that we believe strengthen the requirements for registries. Section 95986(c)(1)(E) was modified to change the amount of professional liability insurance that Offset Project Registries must maintain from fifty million to five million dollars. This change reflects stakeholder comments that the dollar amount was too high and that insurance was not offered at that level of coverage. Sections 95986(c)(2)(A)(1.) and (2.) were modified to specify what type of conflict-of-interest policies Offset Project Registries must have.

M-20. Comment: The addition of performance requirements and non-offset related consulting conducted by registries in section 95986 helps with transparency and conflict of interests. (SCAQMD5)

> **Response:** Thank you for your support.

M-21. Comment: Regarding the performance review of registries in section 95986(k)(5)(B), we appreciate CARB's inclusion of this vital provision. However, a single review every ten years is insufficient. There should also be ongoing oversight over their work and/or a review at least once every five years. (UCS8)

> **Response:** We believe that the registry performance review, combined with ARB's strict oversight of the registries, will provide sufficient assurance that the registries are performing according to the requirements in the regulation. To ensure that our regulatory requirements are being met by Offset Project Operators, we will provide rigorous oversight of our approved Offset Project Registries on an ongoing basis. Oversight functions are part of implementation and need not be specified in the regulation.

Registry Services

M-22. Comment: Under the Kyoto Protocol's offsets program, the Clean Development Mechanism, all data reports (Project Design Documents and Monitoring Reports) are made publicly available along with validation and verification reports. This has been an important source of information for the CDM governing bodies in overseeing the program and discovering reporting errors. The following recommendation enables stakeholders and other experts a chance to catch inaccuracies in the data reports, and provides CARB with another avenue for catching misstatements. Modify section 95987(b)(2) as follows:

> <u>(F) Offset Project Data Report for each year the Offset Project Data Report was verified. Confidential information shall be treated as per section 96021.</u> (UCS8)

> **Response:** We did not make this change. ARB will establish a minimum list of information for each project data report that will be made publically available for each project type as part of program implementation. This standardized approach will provide consistency across the program and ensure that confidential data are protected.

M-23. Comment: In section 95987(e), we are concerned that the verifiers will be informed beforehand which reports will compose the 10 percent of reports audited by the registry and which site visits will be accompanied by a registry representative. If the verifier knows ahead of time which reports and site visits will be audited, the audits only assess the ability of the verifier to do a proper job for those 10 percent of reports. If instead the verifier does not know which reports will be audited, they have an incentive to perform well on all verifications. CARB should specify that the verifier should not know all of the reports that will undergo increased scrutiny. (UCS8)

> **Response:** Every verification report will be subject to review before Registry Offset Credits can be issued. On the audits, ARB and Registry staff will inform the verification body of an audit once a Notice of Verification Services form is submitted. This form includes the names of the specific staff and times of activities that will be part of the audit. If a verification body chooses to make changes to staff or times after being notified of an audit, the verification body will have to discuss the need for changes. This process ensures that verification bodies do not adjust verification teams to represent only the staff perceived to be the most confident, but that audit process allows for ARB and Registries to audit verification staff randomly.

Monitoring, Reporting, and Record Retention Requirements

Record Retention Requirements for Offset Project Operators and Offset Verifiers

M-24. Comment: Section 95976 requires that documents shall be retained in paper, electronic, or other usable format for five years after the end of the crediting period. Clearly a sequestration project could be allowed to establish a final crediting period baseline plus all offsets credits registered and then enter a monitoring process that would not require maintenance of all the preceding decades of documents. Of course during the active crediting period, these records are necessary. (CFA3)

> **Response:** The record retention requirements in section 95976(e)(2) were changed to 15 years following the issuance of ARB offset credits, due to stakeholder concerns about an unnecessarily long record retention requirement for forestry projects. Verifiers are also required to retain related documents for 15 years. The record retention requirements must be extensive enough for verification of each Offset Project Data Report. This provision is necessary to ensure that ARB or an OPR will have enough data to confirm the crediting project has been operating in accordance with the appropriate ARB-approved protocol.

Verification

General Verification Process

M-25. Comment: Requiring too many actions to verify increases costs by increasing the verifiers workload and creating additional paper trails and lowers the flexibility, which is important for small-scale projects. Examples of this include

- The requirement that that offset verification team has a final discussion with the Offset Project Operator (95977.1(b)(3)(R)4(D));

- Understanding data management systems used by Project Operators (95977.1(b)(2)(b)). We believe that it is sufficient for data management systems to comply with the data collection and storage provisions of the Protocol without further requiring additional data.
- Requiring each offset verification to be reviewed by an independent reviewer who has had no involvement with the offset project. Many verification companies only have two or three accredited staff for a particular protocol. We believe it would be better for the ARB accreditation process to require verifiers to have an approved review process rather than require this in the regulations.
- 95977(b)(3)(D) requires verifiers to make a site visit every year. We agree that a verifier should visit a site as part of each verification. However, the wording of this regulation provides little flexibility as to when a site visit should take place. It is not clear whether it should be each calendar year, or within a year of the previous visit or some other period. We suggest that it would be more flexible if verifiers were required to undertake a site visit within two months of the end of the reporting period, allowing the project developer flexibility as to when to schedule a site-visit while still requiring a site visit to take place in order for offsets to be issued. (CIG3)

  Response: Regarding the commenter's first point, in our experience with inventory verification under the MRR, too often the verifiers failed to communicate their findings to their clients before submitting a verification statement to ARB. It is important for offset project developers to understand the findings from verification services from their verifiers.

  On the second point regarding understanding data management systems, the verification team will focus its attention on the systems that directly support data collection or processing for the project. These will be specified in the protocol. We don't believe a change is necessary based on this comment.

  Regarding the third point, we disagree with the comments regarding the requirements for independent review. The commenter's suggestion is contrary to the basic premise that an offset project be subject to an internal independent review to ensure the verification process and findings are appropriate for the offset project.

  On the fourth point, we changed the regulation to require that a site visit for non-sequestration projects must be conducted in the year that offset verification services occurs. For smaller projects that opt to conduct verification every two years, a site visit will only be required in the second year (the year in which full offset verification services are provided).

M-26. Comment: The complexity of verification and the associated costs are the principal barriers currently facing many credible small scale projects from entering the market. The current rules contain examples of verification prescriptions that translate into additional costs, but seem to have little benefit in terms of enhancing project credibility. Section 95977.1(b)(2)(b) requires verifiers to “understand data management systems.” This is a broad and subjective term that could lead to an excessive review, when a clear requirement such as review data management systems to verify adherence to protocol requirements is sufficient. Section 95977.1(b)(3)(R)(1) requires an independent reviewer within the verification body who is not involved in the project. This could further limit the availability of qualified verifiers and lengthen the process for projects to receive issued credits. There are verification firms who lack sufficient personnel to have an additional independent qualified reviewer to fulfill this role although this may change over time. Rather, the requirement could be limited to a lead verifier providing approval and attestation before submission to ARB. (TCT2)

> **Response:** We did not make a change to the requirements for independent review. The commenter’s suggestion is contrary to the basic premise that an offset project be subject to an internal independent review to ensure that the verification process and findings are appropriate for the offset project. Verification covers the systems that are used to collect and process data for the specific project. We do not believe the regulation text as written will lead to an excessive review.

M-27. Comment: CERP appreciates that ARB has added a small degree of flexibility to section 95977.1(b), which now requires each Offset Verification Statement to be independently reviewed within the body by an independent reviewer not involved in services for that offset project. However, this provision remains unreasonably restrictive. For example, if a project utilized one verification body on a project for the full six years otherwise permitted under the conflict of interest requirements, the verification body would have to have available six different individuals who have not worked on the particular project, yet have sufficient expertise with the project type to provide an independent review. This provision adds cost and complexity to offset verification without a corresponding increase in environmental protection. (CERP5)

> **Response:** We did not make this change. The commenter’s suggestion is contrary to the basic premise that an offset project be subject to an internal independent review to ensure that the verification process and findings are appropriate for the offset project.

Offset Verifier Conflict of Interest

M-28. Comment: At present, offsets developers directly hire verifiers to verify the reductions they claim to have made. There is an inherent conflict of interest in the relationship between the developer and the verifier. Under this arrangement, verifiers have incentives to charge less, do less, and be less strict in their assessments in order to be hired again by the same developer or other developers. As experience is gained, we should consider implementing a system which would ensure stronger government oversight over the program and would avoid the conflicts of interest in the current system. Modify section 95977 as follows:

(e) The Board shall periodically review and evaluate the relationships between verifiers and verification bodies and project developers and consider a system where the Board assigns verifiers or verification bodies for each project. (UCS8)

Response: We did not make this change. We believe our conflict-of-interest rules for offset verifiers are very strict and meet a high standard of rigor. We included language requiring offset verifiers and Offset Project Registries to undergo performance reviews. In addition, the regulation proposes a robust monitoring program for offset projects—both the verification that the offsets are real, additional, and enforceable, and that Offset Project Operators, verifiers, and Offset Project Registries are operating according to regulatory requirements. Offset Project Registries are required to conduct oversight of their registry program and randomly audit verifications to ensure that our regulatory requirements are being met by Offset Project Operators and verification bodies. We will provide rigorous oversight of our approved Offset Project Registries. In addition, we designed our regulatory offset verification program to provide a transparent process by which we can review verification documents and fully understand any findings uncovered during the course of verification of an offset project by an ARB accredited verification body. We will also develop an audit and oversight program for offset project verifications. All oversight functions are part of implementation and need not be specified in the regulation.

M-29. Comment: Without strong program oversight and penalties, offset project data reports could easily over-estimate reductions from offsets projects. Offsets are particularly vulnerable to such over-estimation because of conflicts of interest inherent in the relationships between the offsets developers and the verifiers, compounded by the large physical distance between CARB and many of the offsets projects they will oversee around the country and the continent. At present, offsets developers directly hire verifiers to verify the reductions they claim to have made. We put forward the following suggested additions to the verifier and registry oversight provisions in the draft regulation that we believe are important for further strengthening the oversight elements of the regulation.

- All Offset Project Data Reports should be made publicly available. This enables stakeholders and other experts a chance to catch inaccuracies in the data reports, providing CARB with another avenue for catching misstatements. Under the Kyoto Protocol's offsets program, the Clean Development Mechanism, all data reports (project design documents and monitoring reports) are made publicly available along with validation and verification reports. This has been an important source of information for the CDM governing bodies in overseeing the program and discovering reporting problems.
- Regarding the added performance review of registries, we believe that a single review every ten years is insufficient. There should be ongoing oversight over the work of participating registries and a review at least every five years.
- We recommend that CARB periodically review and evaluate the relationships between verifiers and verification bodies and project developers and consider a

system where the Executive Officer assigns verifiers or verification bodies for each project. (UCS9)

Response: We did not change the requirements for posting Offset Project Data Reports. ARB will establish a minimum list of information for each project data report that will be made publically available for each project type as part of program implementation. This standardized approach will provide consistency across the program and ensure that confidential data are protected.

We believe that the registry performance review, combined with ARB's strict oversight of the registries, will provide sufficient assurance that the registries are performing according to the requirements in the regulation. To ensure that our regulatory requirements are being met by Offset Project Operators, we will provide rigorous oversight of our approved Offset Project Registries on an ongoing basis. All oversight functions are part of implementation and need not be specified in the regulation.

We also did not make changes regarding conflict of interest. We believe our conflict-of-interest rules for offset verifiers are very strict and meet a high standard of rigor. We included language requiring offset verifiers and Offset Project Registries to undergo performance reviews. In addition, the regulation proposes a robust monitoring program for offset projects—both the verification that the offsets are real, additional, and enforceable, and that Offset Project Operators, verifiers, and Offset Project Registries are operating according to regulatory requirements. Offset Project Registries are required to conduct oversight of their registry program and randomly audit verifications to ensure that our regulatory requirements are being met by Offset Project Operators and verification bodies. We will provide rigorous oversight of our approved Offset Project Registries. In addition, we designed our regulatory offset verification program to provide a transparent process by which we can review verification documents and fully understand any findings uncovered during the course of verification of an offset project by an ARB-accredited verification body. We will also develop an audit and oversight program for offset project verifications. All oversight functions are part of implementation and need not be specified in the regulation.

Issuance of ARB Offset Credits and Registry Offset Credits

Timing for Issuance

M-30. Comment: To provide greater flexibility, we urge ARB to require registries to issue offsets 15 days after payment has been made. (CIG3)

Response: We did not make this change. We did make changes to the timing for issuance of ARB offset credits in sections 95981 and 95981.1, to shorten the timing for issuance.

Crediting Periods for Compliance Offset Projects

M-31. Comment: The Compliance Offset Protocol for U.S. Forest Projects states in section 3.3 that the crediting period for forest projects is twenty-five years. However, section 95972(b) states that the crediting period for a sequestration offset project shall be no less than 10 years and no more than 30 years. Presumably sequestration offset projects include forest offset projects. At a minimum, the discrepancy in the language is confusing. We recommend that the language in the cap and trade rules replace the language in the Forest Protocol as a thirty year timeframe would provide the greater timeframe necessary to allow meaningful changes in carbon stocks (i.e., forest growth and carbon sequestration) to occur. (NC9)

> **Response:** The regulation specifies a range for sequestration projects, including forestry projects, of 10 to 30 years. The individual protocols for sequestration project types must set a crediting period within this range that is appropriate for that project type. Given this, we do not agree that the crediting period for forest carbon projects should be extended. The intent of a 25-year crediting period is not to limit sequestration of carbon and offset issuance from forest projects. In fact, renewal periods allow for forest projects to sequester carbon and obtain offset credits beyond the 25-year crediting period. A crediting period of 25 years allows for the updating of protocols, if necessary, ensuring that projects use the more up-to-date factors (e.g., leakage, buffer account) and scientific standards.

Invalidation and Forest Reversals

Invalidation Provisions

M-32. Comment: UCS supports the buyer liability language in section 95985(h). (UCS8)

> **Response:** Thank you for your support.

M-33. (multiple comments)
Comment: The ability to mitigate invalidation risk to three years by undertaking second verification is an important option for project operators and developers. However, this option is currently only available to projects verified against ARB's Compliance Protocols. Projects verified under Early Action Offset programs are excluded. This exclusion will cause early action projects to trade at a discount, pointlessly reducing the supply of offsets to the compliance program. We recommend Early Action Offset Program protocols, in particular the CAR Forest Project Protocol, be added to this section. (BLUESOURCE3)

Comment: Section 95985(b)(1)(B) limits the option for three year invalidation to projects registered under the Compliance Protocols. This excludes offsets from projects which have already registered with an Early Action Offset Program from the possibility of reducing their invalidation exposure to 3 years regardless of the number of times they have been verified. We recommend that ARB include protocols from Early Action Offset Programs in this section. (FINITE2)

Comment: Section 95990(l)(1), Invalidation of Early Action Offset Credits, references the full rules for invalidation of ARB offsets credits in section 95985(a) through (h) plus (j), so that Early Action offset credits are subject to the same requirements. Within those requirements, section 95985(b)(1)(B) enables offset project operators/designees to reduce the time period during which offset credits may be invalidated by using a different verifier for later monitoring periods, and meeting other requirements. However, this provision is specifically restricted to projects verified using the ARB Compliance Offset Protocols. This restriction would seem to exclude Early Action offset project operators from the opportunity to eliminate invalidation risk until eight years after issuance. Especially in light of the fact that all Early Action offset credits must undergo two verifications prior to issuance, this exclusion is unwarranted and we hope it was an oversight. (TPI6)

> **Response:** It is our intent that early action offset projects of the corresponding project type as a Compliance Offset Protocol also have the same option for statute of limitations as those developed directly under Compliance Offset Protocols. Once the early action offset credits are issued, they are considered the same as credits issued under the Compliance Offset Protocols.

M-34. (multiple comments)
Comment: Moreover, the regulation as written would require a one-year delay in undertaking this second verification, a period in which the project's credits would trade at a discount, again pointlessly reducing the supply of offsets to the compliance program. We recommend ARB allow second verification to immediately follow first verification prior to initial registration. (BLUESOURCE3)

Comment: Section 95985(b)(1)(B) allows forestry projects to be subject to invalidation for a maximum period of three years if a subsequent project data report is verified by a different verifier within three years of the first. This would require a one-year period between the time of project registration and when a project owner could reduce its invalidation exposure to three years. Since a shorter invalidation period will be more valuable in the market and the risk can be managed more easily, it would be beneficial to forest owners to eliminate the one-year wait. This is possible for ODS offsets per section 95985(b)(1)(A) if they re-verify the project with a different verifier, likely because an ODS project does not require subsequent verifications. However, forestry projects, unlike Ag methane projects, do not require a subsequent site verification for another six years and are eligible for less-intensive verification in the interim years which should afford them the same treatment as ODS projects. We recommend that in addition to the current language, forestry offset projects should be able to utilize the same re-verification process as ODS projects which would allow a forestry project to issue offsets with a three-year invalidation period at the time of registration. (FINITE2)

Comment: Statute of Limitations on Offset Invalidation (Section 95985(b))
Again, we appreciate ARB's decision to provide the option to reduce the statute of limitations for offset invalidation from five to three years if the project is verified by a different verifier within three years, versus the requisite six years. We reiterate the regulation should also include two additional options:

a. Eliminate the Statute of Limitations if the Offset Project Operator or Early Action offset holder elects to use two different verifiers at the time of verification for Compliance projects or regulatory re-verification (i.e. desk review) for Early Action offsets; and

b. Allow the Statute of Limitations to be reduced to one year if a project voluntarily uses a different verifier after one year.

These options allow more flexibility and would continue, as stated in the regulation, to, "encourage a quicker verifier rotation so that any issues that may occur may be uncovered sooner, further enhancing the integrity of the offset program." (CE2CC2)

Response: Offset projects developed under Compliance Offset Protocol Ozone Depleting Substances can undertake an immediate second verification by another verification body; however, the ARB offset credits may still be subject to invalidation for three years. We determined that three years is appropriate because that is sufficient time for any new information regarding an Offset Project Data Report for that project type to be discovered.

For offset projects developed under the other three Compliance Offset Protocols, we included provisions to allow offset projects developed under the other three Compliance Offset Protocols to also qualify for a three year statute of limitation if a different verification body verifies a subsequent Offset Project Data Report from that offset project within three years. This provision provides some flexibility to Offset Project Operators to switch verification bodies before the six year verification body rotation requirement is reached so that the project can be reviewed by a different verifier which could bring to light any irregularities in the offset project data or confirm the validity of the offset project implementation and subsequent issued ARB offset credits.

We included different statute of limitation requirements for the various project types based on the size and volume of credits that may be issued and the cost of conducting a second verification in the same Offset Project Data Report. Double verification on each Offset Project Data Report could be cost prohibitive for some smaller project types.

M-35. Comment: The proposed revised language in section 95985(b) on timing of invalidation of ARB Offset Credits from ODS projects could be interpreted in different ways:

- Credits from ODS projects may be invalidated within 3 years of credit issuance;

- Credits from ODS projects may be invalidated within 3 years of credit issuance but only if those projects are "re-verified" within those 3 years—otherwise the credits may be invalidated up to eight years after credit issuance;
- Early action credits from ODS projects conducted before 2014 that are re-verified may be invalidated within three years of credit issuance—credits from ODS projects that are not re-verified that are completed after 2014 cannot be invalidated.

Because we do not know the intent of the revision, we are not proposing alternative language but we do recommend that the language be clarified. (EOSC4)

> **Response:** The interpretation in the second bullet is correct. The credits may be invalidated within three years as long as the Offset Project Data Report in question has been re-verified by another verification body within three years of credit issuance. If this does not occur, it can be invalidated for up to eight years.

M-36. Comment: Section 95985(b) was amended to provide for a shorter, three-year invalidation period for offsets that are approved under an ARB-approved offset protocol. There is still an eight year invalidation period for other offset types, such as those approved under The Climate Registry. The regulation does not provide a clear rationale for this differing treatment. To avoid unintended impacts and potential favoritism for certain offset programs, PacifiCorp encourages ARB to apply the same invalidation period to all types of offsets. (PACIFICOR4)

> **Response:** The commenter's interpretation of the regulation is incorrect. All projects have the option to reduce the statute of limitation to three years. Section 95985(b)(1)(B) specifies that offset projects developed under the listed protocols may have a statute of limitations of three years if a different verification body verifies a subsequent Offset Project Data Report from that offset project within three years. This provision provides some flexibility to Offset Project Operators to switch verification bodies before the six-year verification body rotation requirement is reached, so that the project can be reviewed by a different verifier, which could bring to light any irregularities in the offset project data or confirm the validity of the offset project implementation and subsequent ARB-issued offset credits. It is our intent that early action offset projects of the corresponding project type as a Compliance Offset Protocol also have the same option for statute of limitations as those developed directly under Compliance Offset Protocols. We will continue to evaluate how to make these provisions more clear as part of a future rulemaking.

M-37. (multiple comments)
Comment: It is not made explicit or clear that the liability for replacement of invalidated forest offset credits in retirement accounts is limited to the Offset Project Operator, not other Forest Owners. This limitation seems to be the purpose of references to "Forest Owner identified in Section 95985(e)(2)" but this is not clear or consistently applied across these sections. Moreover, in many cases it is possible that offset credits will be

transferred into Retirement Accounts from entities other than the Offset Project Operator or any other Forest Owner. We recommend these sections be clarified by replacing “Forest Owner” and “forest owner” with “Offset Project Operator.” (BLUESOURCE3)

Comment: The definition of forest owner has been amended between the July 25th and September 12th drafts to reflect concerns that several entities with interests in a property may be held responsible for reversals. ARB therefore now only allows one “Forest Owner” to be designated as the Offset Project Operator. While this change goes a long way to address prior concerns, a further change is needed. While only one owner can be the Offset Project Operator and only the Offset Project Operator is required to sign the attestation, the “forest owner” is responsible for replacement. Section 95983(c)(3) requires the forest owner to replace in the event of an intentional reversal. Section 95985 Page 290 (i)(1)(D) states that in the event of invalidation the “Forest Owner(s)” is responsible for replacing the invalidated offset in a retirement account. We recommend the term “forest owner” and “Forest Owner(s)” in sections 95983(c)(3), 95985(e)(2), and 95985(i)(1)(D) be clarified so that the Offset Project Operator is responsible for the replacement of intentionally reversed and invalidated offsets. (FINITE2)

Comment: Sections 95985(i)(1)(A), (B), and (C) contain a misplaced reference, which should read “The Forest Owner identified in section 95985(e)~~(2)~~(3) . . .” as section 95985(e)(2) refers to “The entity for which ARB transferred any ARB offset credits from the applicable Offset Project Data Report into the Retirement Account” and Section 95985(e)(3) refers to “. . . for forest offset projects the Forest Owner(s)”. In addition, as noted above in comment #1, we would recommend that these section read “The Offset Project Operator ~~Forest Owner~~ identified in section 959859(e)~~(2)~~(3) . . .” (NEWFOREST3)

> **Response:** Thank you for your comment. We agree that it is confusing and made non-substantive changes to the references in section 95985(i)(1) to clarify that it is always the Forest Owner.

M-38. Comment: Section 95985(g) allows ARB to remove invalidated offsets from any account prior to retirement of the offsets. However, once retired, according to section 95985(i) forest owners are required to replace offsets that are invalidated once they are retired. While it is in the interest of forest owners to reduce liability, in this particular situation it is beneficial to require that landowners also be responsible for replacement of invalidated offsets removed from holding accounts. For each offset sold, a forest owner must assume that the offset will be retired and he will therefore be liable for replacement in the event of invalidation. This extra liability will result in a premium price for forestry offsets. However, due to the fact that any offset sold will be subject to invalidation risk where the offset could disappear at any time prior to retirement, forestry offsets will still face a discount. Therefore, the forest owner must be prepared to take on the invalidation risk of every offset sold, but will not be able to realize the full value of that offset because of the interim risk for the buyer prior to retirement. We recommend that ARB amend this section so that forest owners are liable for the replacement of invalidated offsets removed from holding accounts other than the forest owner's holding account. (FINITE2)

> **Response:** We did not make this change. If the offsets have not been retired, they do not need to be replaced to ARB, they just need to be removed from the system. Holders of the ARB offset credits can seek replacement from Forest Owners through third-party contracts outside of ARB.

M-39. (multiple comments)
Comment: We appreciate that the language in section 95985(c)(1) spells out in more detail how reporting errors are determined. We however repeat the request from our letter dated August 11th that a buffer pool mechanism be established to cover credits for this category to mirror unintentional reversals of forest projects where reporting errors are found to be caused by unintentional errors in calculations. (PFT4)

Comment: A significant cost and leakage driver in the offsets requirements is CARB's ability to decertify an offset after it has been purchased (and even surrendered) and impose liability for this decertification on the offset purchaser. Given the stringency of offset approval, it is questionable why CARB would even propose to decertify offsets that had already qualified under the most rigorous rules. It arbitrarily increases costs and leakage to then punish an offset purchaser by imposing liability for the decertification on the purchaser. This will have the direct effect of pulling allowances out of the market as a hedge against decertified offsets, raising allowance prices and compliance costs and leakage for all capped entities. (AB32IG3)

Comment: While there has been improvement in the language related to the invalidation of offsets, the current process for invalidation still creates large, uninsurable risks for project developers which, in turn, restricts the already limited offset market. The issue of buyer liability is critical to BCSE members seeking to comply under the cap and trade program, as well as those involved as offset verifiers and registries. The BCSE encourages ARB to consider alternatives presented by BCSE members on specific issues related to buyer liability and offset invalidation. (BCFSE2)

Comment: We oppose buyer liability in the event of offset invalidation. Imposition of liability upon the buyer creates uncertainty that could raise transaction costs and suppress the market. While CalChamber recognizes some positive changes were made in the Second-15 Day Rulemaking Package, these changes are not significant enough to relieve our concern that the buyer liability provision will prevent the creation of an adequate offsets market. (CALCHAMBER4)

Comment: The "buyer liability" approach to offset credit invalidation remains unworkable if the goal is to create a robust cap-and-trade program. CERP and others have come forward with an alternative recommendation—a Compliance Buffer Account—that would that provide the same or greater environmental integrity and impose a smaller administrative burden on ARB than a system in which it must chase down every holder and user of credits from a project. (CERP5)

Comment: CERP also commends ARB for adding section 95985(d) to the invalidation section of the regulations. This new addition addresses one of the primary administrative hazards of a buyer liability approach: it will keep offset credits that are under investigation from trading in the market. The provision is very welcome. However, we still remain concerned that a buyer liability regime will lead to scenarios in which even a rumor of ARB activity results in problems in the marketplace and waves of commercial disputes. (CERP5)

Comment: As we stated clearly in prior comments, market certainty and stability are essential elements to the success of the new Cap and Trade program. We continue to believe that the risk that an offset can be invalidated eight years after its certification will undermine market stability and increase program costs. Furthermore, placing that risk of invalidation on the purchaser will lead to unnecessary but substantial increased costs. The State of California must stand behind its offset validation system and, absent fraud or intentional misrepresentation, stand behind a certified offset. This approach will provide the security essential for a strong and cost-effective Cap and Trade program. (WM4)

Comment: IETA, together with other major industry associations, submitted to ARB a white paper in early May 2011 outlining a broad consensus view regarding the market constraints imposed by these provisions, and proposed a workable solution using a “compliance buffer account” funded by offsets withheld at issuance. The primary concerns of this group, which represents the majority of market participants by both volume and consumer base, relating to the invalidation approach can be found in IETA’s August 11 letter submitted in response to the first 15-Day rulemaking package. In addition, the outline of the group’s “Compliance Buffer Account” proposal can be found as Appendix 1 to that letter. We acknowledge and greatly appreciate the attention ARB has devoted to reviewing our efforts and analyzing different scenarios. We realize that ARB staff and officers have integrated significant portions of our collective members’ input into their latest rulemaking language, and that they have genuinely worked to offer improved regulation in this area. With those observations as prologue, IETA offers generally positive reactions and has suggested modifications to the conditions and process for the invalidation of offsets. While we believe we understand the motivations for the implementation of such a rule, IETA respectfully requests the Board give ARB officers and staff the opportunity to explore new consensus during the upcoming implementation phases, and to consider repealing the invalidation rule in section 95985, so that the use of offsets can achieve its highest potential to contain costs for California’s consumers and ratepayers. (IETA4)

Comment: CCEEB is concerned that the risks associated with invalidation of approved offset credits will inhibit the development of the offset market. We appreciate the changes that ARB has made in establishing a criteria and limitations to the invalidation process. However, more work must be done. CCEEB supports the IETA proposal and recommends that ARB should expand the Forest Buffer Account concept to create a compliance buffer account for all offset credits. (CCEEB4)

Comment: In addition, the issue of offset supply becomes even more critical as we rely on it to address impacts to companies from the stringent benchmarks and changes in industry assistance. Therefore, we are even more concerned that offset liability will cause offset supply to be unduly reduced and that any offsets generated will be more costly due to the increased transaction costs from the liability requirements. We believe that taking allowances from the price reserve to replace invalidated offsets is the most cost-effective mechanism to address offset liability. This spreads the minimal cost of replacement among the entire market, which is the most cost-effective liability solution. Without changes to address these issues, large covered entities that invested heavily in the state and created jobs for Californians will be unfairly disadvantaged. (CHEVRON4)

> **Response:** We do not agree that we should eliminate buyer liability associated with the invalidation of ARB offset credits. Requiring the user to replace the invalidated offsets ensures that purchasers and users of offset credits do their due diligence in seeking out high-quality offset credits. We have clear enforcement authority over covered entities that will be using ARB offsets for compliance. If the covered entity replaces any invalidated offset credits, they may then take appropriate action through third-party contractual arrangements they may have established prior to purchase. These arrangements currently exist in the voluntary offset market, and we expect that as the offset market becomes more established, that additional mechanisms to deal with the risk of invalidation will also be established. In the event that the offset credit has not yet been used or retired, it will be canceled in the market tracking system and removed from any Holding or Compliance Accounts. These provisions in no way diminish our authority to assess penalties under section 96014 on any offset project developer or verifier that has provided false information to ARB.

M-40. Comment: We have strong concerns about ARB's "buyer liability" approach to addressing situations in which problems are identified with offset credits at some point after issuance. We believe the risk of such post-issuance problems is small because of the rigor of the ARB offset regulations. However, any policy under which already-issued offset credits carry a risk of invalidation will prevent the development of a market in offsets. In an offsets program, covered entities should be able to rely on the work of verifiers—and on ARB itself as credit issuer. For this reason, making covered entity buyers liable for problems not detected through the regulatory system will impose substantial new costs on buyers without materially reducing the risk that such problems will occur. We continue to believe that the risk that an offset can be invalidated eight years after its certification will undermine market stability and increase program costs. In our view, the State of California must stand behind its offset validation system and, absent fraud or intentional misrepresentation, stand behind a certified offset. This approach will provide the security essential for a strong and cost-effective Cap and Trade program. (RSI)

Response: We do not agree that we should eliminate buyer liability associated with the invalidation of ARB offset credits. Requiring the user to replace the invalidated offsets ensures that purchasers and users of offset credits do their due diligence in seeking out high-quality offset credits. We have clear enforcement authority over covered entities that will be using ARB offsets for compliance. If the covered entity replaces any invalidated offset credits, they may then take appropriate action through third-party contractual arrangements they may have established prior to purchase. These arrangements currently exist in the voluntary offset market, and we expect that as the offset market becomes more established, that additional mechanisms to deal with the risk of invalidation will also be established. In the event that the offset credit has not yet been used or retired, it will be canceled in the market tracking system and removed from any Holding or Compliance Accounts. These provisions in no way diminish our authority to assess penalties under section 96014 on any offset project developer or verifier that has provided false information to ARB.

We do not agree that an offset credit should remain viable under all conditions. To ensure the enforceability of compliance offsets, we need to have the ability to investigate and take action for violations or noncompliance with the regulation. In the event of fraud or malfeasance on the part of project developers or verifiers, there may be cause to invalidate offset credits after they have been issued, to protect the environmental integrity of the program.

M-41. Comment: Section 95985 states that users of credits which at the time of their acquisition were determined to be eligible for use that later turn out to be invalid are required to replace bad credits or suffer sanctions. Making the buyer liable for offset maintenance is problematic because buyers suffer sanctions and/or must replace credits that, though approved by the CARB, later turn out to be invalid; offset transaction and due diligence costs will be higher; programmatic compliance costs will be higher; offsets, when compared to allowances, will become second class compliance instruments; sources on the margin will be more inclined to contribute to leakage by expanding their operations and/or export jobs outside the jurisdiction of AB 32; ignored will be important lessons gained through successful implementation of seller liability provisions in CA, US, and EU programs; and as compared to a seller liability program, the environment will not gain enhanced protection and CARB will have fewer tools to guarantee environmental protection. An approach that relies purely upon the use of high quality credit verifiers (even with multiple reviews) will not work because verifiers are not officers of the government and do not have the ability to stand in CARB's shoes when it comes to determining if the credit creating activity meets the requirements of the rules as may be subsequently determined by the CARB; cannot (and are not paid to) monitor a project after the credits are claimed and/or transferred; will find it very challenging to secure professional liability insurance; will be unable to charge a fee that adequately compensates them for the cost of doing initial and ongoing assessments, paying for liability insurance, and setting aside cash reserves in the event that any credits which have been reviewed by the verifier are subsequently determined to be bad, and will only validate only the project data that is provided them. It will be difficult to write conveyance contracts in a fashion to remove buyer risk because credits may change hands many times, each time with a different buyer and seller. Nor should CARB conclude that the problem of offset reversals can be adequately managed through the use of insurance or financial derivative products because such products may initially reduce the risk of purchasing offsets, but the instruments will, if priced considering consequential damages, sell at prices that dramatically increase transaction costs; given the plethora and magnitude of such risks, a dispassionate observer should be concerned that the insurance provider does not have the ability to understand, much less mitigate the potential financial consequences of offset reversals. BGC Environmental Brokerage Services, L.P. recommends that CARB amend the language in a way that will simultaneously protect the environment, its “currency” (i.e., the offsets), and the buyer by

- Allowing a source to secure CARB/air district review and approval of credits. Specifically, as with offsets useable for new source review, the company creating the reduction must apply to the regulator (i.e., CARB or the anointed Air District) for recognition of such reductions. Upon receipt of an application CARB should approve those credits that satisfy AB 32 criteria and protocols; or deny those that do not, and conditionally approve those credits which may be subject to revocation. Two different kinds of credits will emerge from this process—those with CARB approval (which cannot be invalidated or withdrawn—and which will sell at a premium); and those that lack CARB approval (which the buyer will be aware are at risk of revocation—and which the market will discount).
- Issuing CARB/air district permits to offset-creating sources. Such permits would be issued to sources under CARB control, would mandate the maintenance of the reductions, and sanctions for non-compliance that would have the dual effect of, in the event that the credits are not maintained, protecting the environment and penalizing (and gain recompense from) the offset creator.
- Creating an CARB-administered insurance pool that is either privately funded with credits or through a CARB administered shave that is applied to each credit issued and/or traded. (BGCEBS)

  Response: We do not agree that we should eliminate buyer liability associated with the invalidation of ARB offset credits. Requiring the user to replace the invalidated offsets ensures that purchasers and users of offset credits do their due diligence in seeking out high-quality offset credits. We have clear enforcement authority over covered entities that will be using ARB offsets for compliance. If the covered entity replaces any invalidated offset credits, they may then take appropriate action through third-party contractual arrangements they may have established prior to purchase. These arrangements currently exist in the voluntary offset market, and we expect that as the offset market becomes more established, that additional mechanisms to deal with the risk of invalidation will also be established. In the event that the offset credit has not yet been used or retired, it will be canceled in the market tracking system and removed from any Holding or Compliance Accounts. These provisions in no way diminish ARB's authority to assess penalties under section 96014 on any offset project developer or verifier that has provided false information to ARB.

With regard to the comments related to the development of insurance, we believe that given all of the clarifications to section 95985 the market should be able to quantify and cover the risk associated with invalidation. We expect that insurance products will emerge once the market has been established.

The cap-and-trade program is designed with a clear system for issuance of compliance instruments, under the jurisdiction of ARB to ensure enforceability and oversight of the system. The suggested changes to include air districts would add complexity to the program without further increasing the environmental integrity of the system.

M-42. Comment: In Section 95985 of the proposed rule, ARB continues to make significant modifications and clarifications to the mechanism for the invalidation of offset credits. While Evolution Markets appreciates these changes, we continue to believe the process for invalidating offset credits and resting the liability for replacing the credits solely with the buyer introduces an unacceptable element of uncertainty to the offset market. The result could be a reluctance of market participants to invest in offset projects and a difficulty in creating necessary liquidity in secondary offset markets, which makes low-cost offsets available to all compliance entities. In the interest of constructive engagement on this important issue for the emerging California carbon market, Evolution Markets offers the following feedback on the rule changes recently proposed by ARB:

1.) Reduction in Statute of Limitation: ARB has proposed reducing the statute of limitations from five years to three years for ozone depleting substance (ODS) projects and from eight years to three years for livestock and forestry projects should these projects undergo a second verification within three years of credit issuance. This is a significant improvement, and Evolution Markets believes the emphasis on benefits of double verification is appropriate.

    However, Evolution Markets suggests ARB eliminate the statute of limitation altogether once projects have completed a satisfactory second verification. Presumably, the second verification will be the mechanism for the discovery of any discrepancies that could cause an invalidation. Should the second verification validate the first, ARB should then eliminate that project from the risk of invalidation. The certainty such a change would provide is sure to encourage investment in not only a second verification, which improves the integrity of the offsets program, but also offer sufficient incentive to stimulate investment in offset projects.

2.) Tightened Criteria for Invalidation: ARB has modified its proposal to permit invalidation only if the overstatement of reductions is more than 5% of the total issuance, the project activity was not in accordance with federal, state, or local environmental regulations, or the credits had already been used under another voluntary or mandatory program.

ARB also now has the ability to invalidate only the amount of credits actually overstated, and these invalidations will be imposed on all holders of credits from the project in question on a *pro rata* basis. Evolution Markets supports both of these changes and believes they will assist in encouraging investments in offset projects.

3.) Extended Replacement Time for Invalidated Offsets: Evolution Markets also supports ARB's suggested rule change to allow entities that have used invalidated offsets for compliance to take up to six months to replace these credits. Although Evolution Markets anticipates the actual amount of invalidated offsets to be small, providing this flexibility to compliance entities will protect against market disruptions that could have an adverse impact on credit prices and raise the overall costs of compliance. (EVMKTS3)

Response: We do not agree that we should eliminate buyer liability associated with the invalidation of ARB offset credits. Requiring the user to replace the invalidated offsets ensures that purchasers and users of offset credits do their due diligence in seeking out high-quality offset credits. We have clear enforcement authority over covered entities that will be using ARB offsets for compliance. If the covered entity replaces any invalidated offset credits, they may then take appropriate action through third-party contractual arrangements they may have established prior to purchase. These arrangements currently exist in the voluntary offset market, and we expect that as the offset market becomes more established, that additional mechanisms to deal with the risk of invalidation will also be established. In the event that the offset credit has not yet been used or retired, it will be canceled in the market tracking system and removed from any Holding or Compliance Accounts. These provisions in no way diminish ARB's authority to assess penalties under section 96014 on any offset project developer or verifier that has provided false information to ARB.

We do not agree that ARB offset credits should no longer be invalidated in the event that a second verification is performed on the Offset Project Data Report. The minimum statute of limitations is three years if the Offset Project Data Report or a subsequent Offset Project Data Report, depending on project type, is verified by a different verifier within that time frame. If the offset project does not qualify under these requirements the default statute of limitations is eight years. We do not believe that any time period less than three years would provide sufficient time to detect all relevant new information or uncover any mistakes that verifiers may have missed or may have been unintentionally omitted.

Thank you for your support under items 2 and 3.

M-43. Comment: Regarding the first instance of an invalidation determination (section 95985(c)(1), many market participants believe that it ought to be the responsibility of the project owner or other relevant entity that committed the error (not automatically the buyer as the first instance), to reimburse lost credits due to invalidation. This does not eliminate the ultimate liability of the buyer, and does not change any duties of the regulator. But instead it establishes a clearer chain of claims when appropriate, and puts even more incentive on project owners and investors to initiate and execute projects of the highest environmental integrity in the first place. (IETA4)

> **Response:** We do not agree that the responsible party of an invalidated ARB offset credit should be the offset developer. We have clear enforcement authority over covered entities that will be using ARB offsets for compliance. If the covered entity replaces any invalidated offset credits, they may then take appropriate action through third-party contractual arrangements they may have established prior to purchase. These arrangements currently exist in the voluntary offset market, and we expect that as the offset market becomes more established, that additional mechanisms to deal with the risk of invalidation will also be established. In the event that the offset credit has not yet been used or retired, it will be canceled in the market tracking system and removed from any Holding or Compliance Accounts. Requiring the user to replace the invalidated offsets ensures that purchasers and users of offset credits do their due diligence in seeking out high-quality offset credits.

M-44. (multiple comments)
Comment: The language contained in section 95985(c)(2) is overly broad and could lead to invalidation of large numbers of offset credits for issues that are either immaterial to the offsets themselves, and/or are minor technical violations that are in the process of being remedied and for which no actual enforcement action has been taken by the relevant agency. Further, these violations could be beyond the control of a Forest Owner in situations where a court may have issued a change in interpretation of the law, but no administrative remedies for compliance are yet available. At the very least, a violation should be material, and should be the subject of a final notice of non-compliance after the violation has been through its relevant adjudication process with the jurisdiction of authority over the relevant statute and regulations. Modify section 95985(c)(2) as follows:

> The offset project activity and implementation of the offset project was found by a court or administrative body of competent jurisdiction to be not in material accordance with all local, state, or national environmental and health and safety statutes and regulations, as interpreted by a court of competent jurisdiction from which an appeal cannot be taken, during the Reporting Period for which the ARB offset credit was issued. (PFT4)

Comment: Consider amending section 95985(c)(2) to acknowledge legal ambiguity and de minimis and inadvertent non-compliance with applicable laws and regulations.

Section 95985(c)(2) states that ARB “may determine that an ARB offset credit is invalid for the following reasons . . . The offset project activity and implementation of the offset project was not in accordance with all local, state, or national environmental and health and safety regulations during the Reporting Period for which the ARB offset credit was issued”. In the event of an invalidation for this reason, under the current draft the Forest Owner must replace all credits that were issued to an invalidated offset project data report and that had been retired after issuance. As drafted, this provision does not account for common situations of legal ambiguity, inadvertent or de minimis non-compliance with applicable laws and regulations, and patterns of enforcement by agencies with enforcement discretion over applicable laws and regulations. We would recommend changes to section 95985(c)(2) that would give ARB clearer discretion to avoid credit invalidation in situations of legal ambiguity, de minimis violations or pending actions by enforcement agencies.

For example, it is a common occurrence for appellate courts in the United States to interpret federal environmental laws and regulations in different ways. It can take years before these regional discrepancies are resolved by the Supreme Court, and in the meantime it may be impossible for forest owners to comply with a given court’s interpretation of an environmental law because the regulating agency has not yet created a permitting avenue for such compliance. In such cases a forest owner is technically in violation of a national environmental regulation but has no way to comply, and the law may change again in a year or two. ARB should have clear discretion to avoid credit invalidation in such instances where legal non-compliance is beyond the control of the landowner.

Similarly, many environmental regulations are complex and compliance is complicated. The California Forest Practice Rules, for example, contain detailed provisions related to logging roads and stream crossings. Regional Water Quality Control Boards may interpret applicable law differently and require different capital improvements of logging roads from Forest Owners. In most instances, if a forest owner is found by a regulating agency to not be in complete compliance with a regulation despite good faith efforts at adherence, the forest owner is given time by the regulating agency to comply with the regulation. ARB should not be in the business of second-guessing regulating agencies and imposing penalties for temporary non-compliance, and ARB should have clear discretion to avoid credit invalidation in situations of de minimis non-compliance.

While the permissive “may” language in section 95985(c)(2) does make clear that ARB has enforcement discretion over credit invalidation, we would recommend the changes to section 95985(c)(2) below. These changes would: (1) protect ARB from being forced to adjudicate legal non-compliance in areas that are regulated by a different agency; (2) protect ARB from being forced to invalidate credits for immaterial non-compliance; and (3) protect ARB from being forced to invalidate credits when a judicial interpretation of an applicable statute or regulation is not yet settled. Modify section 95985(c)(2) as follows:

(2) The offset project activity and implementation of the offset project was found by a court or regulatory body of competent jurisdiction to be not in material accordance with all local, state, or national environmental and health and safety statutes and regulations, as interpreted by a court of competent jurisdiction from which an appeal cannot be taken, during the Reporting Period for which the ARB offset credit was issued. (NEWFOREST3)

Comment: We recommend modifying section 95985(c)(2) to add a materiality element, i.e., by limiting the scope of the provision to situations in which a project is "not in material accordance" with regulations. (CERP5)

Comment: The language in section 95985(c)(2) regarding invalidation due to the project activity or its implementation not being "in accordance with all local, state or national environmental and health and safety regulations…" should have additional specificity. To provide additional certainty to this provision and those relying on it, we recommend that CARB provide additional guidance regarding how such a determination would be made. For example, such determinations could be based on agency enforcement actions or court decisions. (NC9)

Comment: CERP members have developed deep concerns about the breadth of the language included in section 95985(c)(2), under which invalidation can occur if the project activity "was not in accordance with all local, state, or national environmental and health and safety regulations" during the relevant Reporting Period. As a practical matter, project activities may temporarily fall out of compliance with any number of unrelated legal requirements in a manner that has no material effect on the extent to which the project generates real emission reductions or removals. The requirement under (c)(2), therefore, could result in "gotcha" scenarios that undermine the offsets program. (CERP5)

Comment: Section 95985(c)(2) invalidates offsets if the project activity "was not in accordance with all local, state, or national environmental and health and safety regulations...." This is very broad and vague. There should be some nexus between the failure to accord and the goals and objectives of the Rules. Given the thousands of health and safety regulations, there may be technical violations that have no material effect on health and safety, much less ARB's air quality objectives. In addition, there should be some definition of what constitutes a "determination" that results in an invalidation. Will ARB or a verifier determine what may ultimately be regulatory or judicial facts and circumstances as to whether the project activity or its implementation is in "accord"' with a regulation? We recommend that the Rules be changed to provide that offsets are invalidated only if the appropriate agency or court has finally and definitively found the project activity to not be in accord with a regulation. (TCF3)

Comment: On the surface, IETA is comfortable with the spirit of capturing illegal activity in the offset invalidation provisions of section 95985(b)(3). The question arises when the wrong codes of laws or regulations are applied to making the determination that illegal behavior occurred; the regulation (c)(2) currently states "…not in accordance with all local, state, or national environmental and health and safety regulations…;" We respectfully ask that at a minimum the regulation say that "all relevant and applicable" instead of just "all," and that ARB staff narrow this language further to minimize the chance for nuisance claims and the potentially negative legal exposures this current language poses for ARB. (IETA4)

> **Response:** We did not make the requested changes to sections 95985(c)(2) and (c)(3) and believe that the text is clear in its intent. We do not want to issue offset credits for projects that are not in conformance with applicable regulations. We will continue to coordinate with stakeholders to identify further refinements and criteria as part of a future rulemaking.

M-45. Comment: The determination and process of invalidation, at present, do not require or allow any independent assessment concerning the amount of the overstatement. The Offset Project Operator should be able to request a second certification of the emissions reduction and ARB should take the result of any second verification into account. The current approach may result in ARB interpreting Protocol or other guidance in a different way from that on an experienced verifier. At minimum the Offset Project Operator should have the right to, and ARB should be required to, consider a second, independent opinion. (CIG3)

> **Response:** We did not make this change. ARB is the only agency that can determine whether ARB offset credits are invalid. We do not agree that this administrative step is necessary, as we will base the invalidation on the third-party verification that was performed by an ARB-accredited verifier.

M-46. (multiple comments)
Comment: IETA is encouraged by many of the revisions proposed to section 95985, and respectfully submits that more specificity is needed for when ARB determines that an offset project performance has been overstated by more than 5 percent (section 95985 (c)(1)). While it is not yet clear that the 'yardstick' for the project's performance is the Offset Project Data Report, it also is not clear 1) how the grounds for invalidation can occur, 2) whether it is based on a second verification or 3) if determinations will get made by a generally accepted industry auditor or by a related regulator or another official body. Regardless of the liability approach ARB adopts, it is important to ensure that the process for offset credit invalidation is well designed.

Comment: IETA is pleased to tightening of the offset invalidation language in section 95985(b)(2) regarding the liability once the 5 percent threshold is exceeded, such that only the difference—i.e. the overstatement beyond 5 percent gets invalidated. However, as a practical matter, the means by which the "errors in emissions reductions achieved" versus the Offset Project Data Report is calculated needs more clarity. How will ARB make this finding? How will ARB make the calculation? As a further practical matter, this error and quantitative finding could be exposed and assessed in the second validation and that determination could be final. If there were legal issues (e.g. the Verifier or some other party was suspect in some way) around the circumstances of the second validation, then ARB would naturally be the “next judge” to make the finding and subsequent assessment. And of course, if the project did not undergo a second validation, then ARB would be the natural authority for making the finding and quantifying the subsequent invalidations. (IETA4)

> **Response:** The purpose of including section 95985(c)(1) in the regulation is to detect any relevant new information or uncover any mistakes that a verifier may have missed. It would not be based on a second verification. It would be based on the verification that was performed by an ARB-accredited verifier. ARB is the only agency that can determine whether ARB offset credits are invalid. This section also includes details in what information shall be considered by ARB in making a finding.

M-47. (multiple comments)
Comment: For the situations defined in section 95985(c)(3), forest owners have no control over how their credits are used after they are sold. In this instance, holders of credits should be liable for invalidated credits if after an ARB offset credit was sold, an entity used it to comply with some other obligation in addition to using it as a compliance instrument in the California Cap and Trade system. (PFT4)

Comment: TNC commends staff’s recent improvements to the forest owner definition that help clarify that only entities with an interest in real property would qualify as a forest owner. While clear, this broad definition coupled with the liability provisions still casts a brought net of liability without specifically establishing a chain of liability to provide greater certainty to transactions. The forest owner is identified as the liable party for replacing forest offsets in instances of intentional reversals and invalidation. This means that at any given time, the fee owner, the easement holder, the timber rights holder and/or the carbon rights holder could be liable for replacing forest offsets. This uncertainty could discourage transactions and the development of offset projects. TNC recommends that CARB staff identify that the offset project operator (OPO) would initially be held responsible for replacement of offsets in the events of invalidation or intentional reversals. Since the regulations state that only one forest owner can be the OPO, a forest owner would still be liable for replacement of offsets. This approach would provide more certainty by identifying up front who would be initially responsible (i.e., the OPO). Furthermore, it would not preclude other parties from ultimately being responsible for offset replacement. (NC9)

Comment: PFT thinks there is still some inconsistency in the regulations in how the definition of Forest Owner works in relation to a forest Project Operator. The definition states that one Forest Owner must be designated as the Project Operator, and language was removed from the definition that is consistent with keeping responsibility for forest offset projects clear. However, there are several places in the regulations where responsibility is split between the Project Operator and the Forest Owner. For instance, Project Operators sign attestations when a project is listed accepting legal responsibility for the integrity of the project and accepting the jurisdiction of the State of California for enforcement of the cap and trade regulations. On the other hand, the

Forest Owner(s) is/are responsible for paying back credits in the case of intentional reversals and credit invalidation. Given that by definition, there can be more than one forest owner (e.g., owner in fee of the land and owner of additional forest rights in an easement), we recommend that the regulatory language allow for one forest owner, the Project Operator, to be designated as responsible for all aspects of a project, including submitting relevant reporting data, signing attestations, and replacing credits in the case of reversals or invalidation. The one forest owner party responsible should be identified in the listing information. In the case of invalidation or reversals, language could be added to name other forest owners in the event that the Project Operator is no longer in business. (PFT4)

> **Response:** We disagree and did not make this change. Forest Owners have physical custody of the carbon stocks, and therefore should have liability for the offset projects. The Forest Owners can establish contractual arrangements among themselves for establishing specific responsibility for invalidated credits.

M-48. Comment: CE2 appreciates the adjustments and clarifications that ARB has made regarding offset invalidation. However, we reiterate our proposal that ARB develop and manage a separate "Invalidation Buffer Account." Unfortunately, requiring regulated entities to replace invalidated credits will unnecessarily restrict the supply of high quality offsets without real net environmental gains. The problem lies in the assumed benefits of this system. Buyers (regulated entities) are assumed to be protected from receiving bad credits through use of insurance mechanisms, trained offset verifiers, innovative contracting, and extensive due diligence. It is also assumed that ARB is more likely to recover an invalidated offset credit if a regulated entity is held liable for its replacement. There are several fundamental problems with these assumptions:

> a. No private carbon offset insurance products currently exist. Given the low overall number of potential offsets that can be used in the California market (up to 218 $MMTCO_2e$) it is not practical to assume that a product will be actuarially viable or cost effective. If ARB believes this product is or could be available and cost effective, ARB should define the parameters of an acceptable policy and mandate its use.
> b. The private sector cannot mandate that all projects and offset holders purchase a common insurance policy or participate in a common buffer account. Without a common policy or buffer account, economies of scale cannot be achieved and transaction costs will increase effectiveness of offsets and decreasing investment in emission reductions outside of the capped sectors.
> c. If a voluntary insurance policy or buffer account were to exist, it would suffer from "adverse selection" as (1) project developers and sellers would be incentivized to submit only their riskiest projects to the voluntary insurance policy or buffer account; and (2) they would sell the least risky projects directly to large compliance entities via bilateral contract.
> d. If only the riskiest projects trade on exchanges, transparency will be sacrificed and market oversight would be more difficult.

e. Smaller compliance entities would not have equal access to quality offsets. Larger entities are better able to diversify invalidation risk across multiple projects and counterparties and devote staff to evaluating the invalidation risk of individual offset projects.

The solution to addressing the problems associated with holding regulated entities responsible for replacing an invalidated offset credit is to mirror the current ARB Forest Buffer Account structure and procedures to apply separately (and additionally) to all Compliance offset projects. Once an offset is invalidated by ARB, the first step would be to notify the Offset Project Operator and allow them six months to replace the invalidated credits. If the Offset Project Operator does not replace the invalidated credits within six months, ARB would retire credits from the ARB Invalidation Buffer Account. If the credits are not replaced with six months of ARB's retirement, the Offset Project Operator would be subject to enforcement action. This system would reduce transaction costs while maintaining environmental integrity in the overall cap and trade system. This system would also align the incentives of Offset Project Operators, verifiers, buyers, sellers, and regulated entities, as well as result in a fungible, commoditized offset market which is equitable, accessible by all compliance entities, and would allow transparent trading and clearing via exchange.

Relying on the establishment of an Invalidation Buffer Account could be seen as increasing the risk of default to ARB and placing new administrative burdens on an already stressed ARB staff. However, the changes proposed herein are merely an extension of the buffer account management and enforcement action responsibilities already undertaken by ARB for forestry projects, and will actually reduce invalidation risk because the incentives of Offset Project Operators will be properly aligned to ensure the quality of their projects.

Whereas section 95985(h)(C)(l) states that the Offset Project Operator would be responsible for replacement in the event that the entity who retired the credits is no longer in business, the chain of responsibility should simply be reversed to first require that the Offset Project Operator replace, while the retiring entity is responsible only in the event that the Offset Project Operator is no longer in business. (CE2CC2)

Response: We do not agree that the responsible party of an invalidated ARB offset credit should be the offset developer or that we should eliminate buyer liability associated with the invalidation of ARB offset credits. Requiring the user to replace the invalidated offsets ensures that purchasers and users of offset credits do their due diligence in seeking out high-quality offset credits. We have clear enforcement authority over covered entities that will be using ARB offsets for compliance. If the covered entity replaces any invalidated offset credits, they may then take appropriate action through third-party contractual arrangements they may have established prior to purchase. These arrangements currently exist in the voluntary offset market, and we expect that as the offset market becomes more established, that additional mechanisms to deal with the risk of invalidation will also be established. In the event that the offset credit has not yet been used or retired, it will be canceled in the market tracking system and removed from any Holding or Compliance Accounts. These provisions in no way diminish ARB's authority to assess penalties under section 96014 on any offset project developer or verifier that has provided false information to ARB.

With regard to the comments related to the development of insurance, we believe that given all of the clarifications to section 95985 the market should be able to quantify and cover the risk associated with invalidation. We expect that insurance products will emerge once the market has been established.

M-49. Comment: Under the current proposal, ARB proposes to look to the compliance entity to "make good" for any invalidated allowances previously submitted for compliance purposes. If the compliance entity is out of existence, or otherwise unable to make good, then ARB proposes to have secondary recourse to the offset project owner/developer. MSCG strongly believes that this sequence should be reversed. ARB should first approach the offset project owner/developer to "make good" for any offset credits created by its project that are invalidated. Only if it is unable to meet that obligation should ARB look to the compliance entity as a matter of secondary recourse. Using this approach provides ARB with exactly the same remedies as the current draft, but better comports with the (hopefully) universally accepted principle that the entity that causes a problem should be responsible for fixing it. The legal obligation to replace invalidated credits can be instilled as part of the conditions for project approval and offset credit issuance. Indeed, such an obligation should go beyond just replacing offset credits previously submitted for compliance, and should include replacement for all invalidated offset credits, regardless of where currently held. The replacement can be made using any still-valid credits held by the owner/developer, or by buying credits or allowances on the open market and distributing them to the "victimized" holders. This approach would also address a potential inequity, whereby the project owner/developer that has some portion of its credits invalidated, appears to be able to keep its "ill-gotten" proceeds. Nothing about the "buyer liability" approach appears to create a mechanism whereby the offset owner/developer must relinquish the revenues associated with the invalidated credits. For all the reasons discussed above, MSCG strongly believes that good public policy principles are best served by looking first to the owner/developer for redress on invalidated credits, with only secondary recourse to compliance entities. (MSCG4)

Response: We do not agree that the responsible party of an invalidated ARB offset credit should be the offset developer or that we should eliminate buyer liability associated with the invalidation of ARB offset credits. Requiring the user to replace the invalidated offsets ensures that purchasers and users of offset credits do their due diligence in seeking out high-quality offset credits. We have clear enforcement authority over covered entities that will be using ARB offsets for compliance. If the covered entity replaces any invalidated offset credits, they may then take appropriate action through third-party contractual arrangements they may have established prior to purchase. These arrangements currently exist in the voluntary offset market, and we expect that as the offset market becomes more established, that additional mechanisms to deal with the risk of invalidation will also be established. In the event that the offset credit has not yet been used or retired, it will be canceled in the market tracking system and removed from any Holding or Compliance Accounts. These provisions in no way diminish ARB's authority to assess penalties under section 96014 on any offset project developer or verifier that has provided false information to ARB.

M-50. Comment: "Forest Owner" is defined in section 95802(a)(109) (page A-21) to include "the owner of any interest in the real . . . property involved in a forest offset project", excluding government agency third-party beneficiaries of conservation easements, but a single Forest Owner must be designated as the Offset Project Operator. We noted in our August 8, 2011 comments that this could be interpreted to include real property interest holders who have no control over forest management, such as a right-of-way easement holder, and recommended that the definition of "Forest Owner" be limited to those with real property interests that affect forest management—the fee owner, any holder of timber rights, and any holder of a working forest conservation easement that touches or concerns forest management, as applicable. Only the Offset Project Operator is required to submit an attestation with the project affirming voluntary participation in the cap and trade scheme and agreeing to personal jurisdiction and venue in California courts pursuant to section 95975(c)(2) (page A-202). At the same time, the credit invalidation and replacement provisions in section 95985(i) (pages A-288 to A-290) state that "The Forest Owner . . . must replace ARB offset credits" in the event that credits in a Retirement Account are invalidated (emphasis added). ARB and the State of California will not, however, have clear jurisdiction to enforce the cap and trade regulations against Forest Owners who are not required to submit an attestation to ARB pursuant to section 95975(c)(2). Furthermore, because the definition of Forest Owner is drafted so broadly as to include owners of real property interests that have no impact on forest management, it would be unnecessary and infeasible to seek attestations from all entities that qualify as Forest Owners as that definition is currently drafted. (Real property interest holders with no capacity to affect forest management should not be Forest Owners. For example, it would be unrealistic to structure the regulation such that an owner of a private driveway through a forest area could face a contingent financial liability due to the forest management of an entirely different party).

In summary, while "Forest Owner" is defined to include all holders of a real property interest on the project area, in the most recent draft only one Forest Owner is the Offset Project Operator, and only the Offset Project Operator submits an attestation submitting to personal jurisdiction and venue in California courts. However, in the section on credit invalidation, the Forest Owner rather than the Offset Project Operator is responsible for replacing invalidated credits that have been retired. The change in the definition of "Forest Owner" in this draft indicates an appropriate and reasonable intention to hold (in the first instance) only the Offset Project Operator legally liable for proper and lawful operation of the offset project. We would therefore recommend that ARB amend section 95985(i)(1) and (2) to state that only the Offset Project Operator (*not* the Forest Owner) must replace ARB offset credits in the event of invalidation of a credit in a Retirement Account pursuant to section 95985. We also recommend the following change to section 95985(e)(3). This would ensure that section 95985 properly reflects the changes to the definition of Forest Owner, with only one being designated an Offset Project Operator, and the scope of the State of California's enforcement capabilities pursuant to section 95985(c)(2). Modify section 95985(e)(3) as follows:

> (3) The Offset Project Operator and Authorized Project Designee~~, and, for forest offset projects the Forest Owner(s)~~. (NEWFOREST3)

> **Response:** At least one forest owner has to be delegated as an offset project developer. It is the forest owners that have physical custody of the sequestered carbon stocks. We acknowledge there may be more than one forest owner for a project, and we advise those parties to develop third-party contracts on roles, responsibilities, and liabilities when participating as a group in the Compliance Offsets program.

M-51. (multiple comments)
Comment: Section 95985(b)(1)(A) and (B) should read "An O~~o~~ffset P~~p~~roject Data Report developed . . ." (NEWFOREST3)

Comment: The definition of "$TOT_{holding}$" might be clearer in section 95985(g)(1) if it was rephrased as "'$TOT_{holding}$' is the total number of ARB offset credits from the applicable Offset Project Data Report currently being held in a Compliance and/or Holding Account by each party identified in section 95985(e)(1) ~~for the applicable Offset Project Data Report~~." (NEWFOREST3)

Comment: Section 95985, as a whole, uses the phrase "invalidation of offset projects" interchangeably with "invalidation of offset credits." We recommend that all references to "invalidation of offset projects" be eliminated to make clear that only offset project credits are subject to invalidation. (TPI6)

> **Response:** We did not make these changes. We believe the language is clear as written and conveys the intent.

M-52. Comment: Section 96985(e)(2) should read "The entit~~y~~ies for which ARB transferred any ARB offset credits . . ." (NEWFOREST3)

> **Response:** Thank you. We made this non-substantive change in the regulation.

M-53. (multiple comments)
Comment: CERP supports the changes to the regulatory language that allow for a three year statute of limitations for ODS projects if an Offset Project Data Report for a particular credit is re-verified by a different verifier within three years. We also support the provision allowing for a three year statute of limitations for other offset project types—currently livestock, urban forest and forest projects—when they have a subsequent Offset Project Data Report re-verified by a different verifier and issued a Positive or Qualified Positive Offset Verification Statement within three years of

issuance. (section 95985(a)(1)). CERP appreciates these changes because the revised process will maintain a very high level of environmental integrity while also allowing projects the flexibility to undertake a second verification to shorten the statute of limitations period and thus remove the cloud of invalidation uncertainty in a timely manner. (CERP5)

Comment: We extend appreciation for ensuring that an issued credit not become subject to invalidation, in the future, due to a change to the underlying protocol. (IETA4)

Comment: IETA is pleased to see the elimination of section 95985(b)(1)) of the offset invalidation rules. It represented a broad reach of oversight authority beyond discrepancies that would have material effects on the environmental integrity of projects. (IETA4)

Comment: SCE appreciates the improvements that ARB has made to the offset provisions of the regulation, particularly the increased overall clarity in the offset rules. SCE especially applauds the strengthening of the criteria by which ARB may invalidate offset credits that have already been validated. Specifically, ARB has shortened the timeframe for offset invalidation from five years to three years for ozone-depleting substance projects. In addition, ARB has allowed for a second verification to shorten the invalidation timeframe for projects created under the other three offset protocols. Section 95990, which addresses early action offset credit provisions, has been revised and much improved. For example, the latest date that an early action offset project can be registered has been changed from January 1, 2013 to January 1, 2014. In addition, ARB has modified the rules to allow GHG reductions that occur in 2014 under an early action protocol to be verified by September 30, 2015. ARB has also revised Section 95985 to create a clear process for determining which offsets have been invalidated and must be retired. SCE supports the provisions of Section 95985, which also identifies the responsible parties if an offset project overstates its GHG emissions reductions. In addition, the replacement provisions are limited to only those offsets that have been retired. These revisions to the offset reversal provisions will provide market participants with increased certainty and liquidity, which will lead to additional opportunities for cost containment. (SCE4)

> **Response:** Thank you for your support.

M-54. Comment: Section 95985(c)(3) invalidates offsets if ARB determines that “offset credits have been issued in any other voluntary or mandatory program with the same offset project boundary....” This puts the burden on the Offset Project Operator to determine what its various holders may have done with their offset credits, which is infeasible. ARB should require holders of offset credits to attest that they have not used the offset in any other voluntary or mandatory program and hold them liable, not the Offset Project Operator, if they have. (TCF3)

> **Response:** We disagree that this is not the liability of the holder. Holders are allowed to sell the offset credits but do not have the rights to the offset project.

New section 95975(c)(5) of the regulation now requires that an Offset Project Operator or Authorized Project Designee disclose any offset credits issued for the same project for any other purposes in any other program. In addition, we added new attestations to section 95981(c). Offset Project Operators and Authorized Project Designees must make these attestation(s) in order for ARB to issue offset credits. Therefore, if ARB finds that ARB offset credits were issued to the offset project for the same GHG reductions or GHG removal enhancements, ARB may invalidate the ARB offset credits pursuant to section 95985, and it will be the Offset Project Operator or Authorized Project Designee that will have violated the provisions of the regulation.

M-55. (multiple comments)
Comment: In its earlier language, ARB introduced a statute of limitations of eight years for invalidation of already-issued offset credits with a shortening of the statute of limitations to five years if a project undergoes a second verification after three years of issuance of the credits. We are extremely pleased to see ARB integrate reforms that tightened the time limit to three years for ODS projects and three reporting periods for all other types of projects, but in practice we believe this could still be shortened and in fact eliminated for all but the most extreme circumstances. We have noted, as have ARB officers, that the second verification accords a significant “yardstick of credibility;” ARB considers the validity of offset credits sufficiently established and quantified, once the project has been reviewed by a second, independent ARB-accredited verifier and the second verifier has not identified any grounds for invalidation. To this end, IETA urges ARB simply to allow the invalidation period to expire upon the date of ARB’s acceptance of the second verification. Because the second independent verification is the means by which a credit may be invalidated, a positive or successful second verification logically fulfills ARB’s need to confirm and attest to the quality of a credit. IETA believes this yardstick of credibility is a well-grounded tool for standing by the environmental integrity of issued offsets. Also, it provides a basis for minimizing an otherwise extended period of time during which issued—and “double-approved” for all intents and purposes—offset credits remain subject to invalidation. In particular, we think it would lead many entities buying ODS projects in the offsets market to manage their risk by obtaining a second verification of the data report immediately following the issuance of credits—furthering the credibility of the program. In short, the second verification acts as the de facto insurance for ODS offsets. Although we cannot speculate that insurance products will emerge to manage the risk of validation (whether before and after the second verification), this much shorter period will enable a more manageable time horizon for transactions. The second verification public record will also build a data set that might enable better risk management processes overall. For non-ODS projects, a process to review these projects’ Data Reports—analogous to the ARB early action process—by a second independent verifier could convey the same benefit and achieve the same result. Thus, the second verification provides assurance of the credit quality and an arbitrary delay provides no greater objective assurances regarding its environmental integrity. However, the marketplace will not consider the credit fully valid, and its marketability will be impaired for the length of that period of delay. In addition, it will likely offer the marketplace sufficient certainty to encourage

investment in offset projects, ensuring adequate supply of credits for use in controlling the costs of the program. (IETA4)

Comment: The Proposed Changes to section 95985(b) add a provision under which the period of time during which the offset credit is subject to invalidation ("invalidation period") can be shortened from eight years to three years if re-verification or subsequent verification by a different verifier takes place within the three years. Section 95985(b) should be revised further so that the invalidation period expires upon the date of the re-verification or subsequent verification. There is no reason to require that a second verification "sit" until the expiration of the three year period before lifting the shadow of invalidation. Nothing is gained from the passage of time. However, much is lost: the marketplace will not consider an offset credit to be fully valid, fungible, and marketable until the invalidation period has ended. In addition, some ambiguities in the drafting of the invalidation period should be addressed. For example, the phrase in section 95985(b)(1)(B) "may only be subject to invalidation within three Reporting Periods if a subsequent Offset Project Data Report for that offset project is verified..." is confusing, as it seems to indicate that invalidation may only occur if a subsequent report is verified. The numbering of section 95985(b) should also be revised, as there is a section (b)(1) but no (b)(2). Modify section 95985(b) as follows:

> (b) Timeframe for Invalidation. ARB may invalidate an ARB offset credit pursuant to this section ~~within the following timeframe~~ at any time until eight years after issuance if a determination is made pursuant to section 95985(f), unless one of the requirements is met:
>
> > ~~(1) Within eight years of issuance of an ARB offset credit unless one of the following requirements is met;~~
> >
> > > (~~A~~1) ~~An offset project developed under Compliance Offset Protocol Ozone Depleting Substances Projects, [DATE], may only be subject to invalidation within three years of issuance of an ARB offset credit i~~If the Offset Project Data Report for an offset project developed under Compliance Offset Protocol Ozone Depleting Substances Projects, [DATE], is re-verified pursuant to sections 95977 through 95978 by a different offset verification body ~~within those three years~~, the ARB offset credits issued pursuant to the Offset Project Data Report may not be invalidated after the date of the re-verification; or
> > >
> > > (~~B~~2) ~~An offset project developed under the protocols listed below, may only be subject to invalidation within three Reporting Periods i~~If a subsequent Offset Project Data Report for an~~that~~ offset project developed under the protocols listed below is verified pursuant to sections 95977 through 95978 by a different offset verification body and issued a Positive Offset or Qualified Positive Offset Verification Statement, ~~within three years of issuance of~~ the ARB o~~O~~ffset c~~C~~redits issued under the first Offset Project Data Report may not be invalidated after the date of the subsequent Offset Project Data

Report. This provision applies if an offset project is developed under one of the following Compliance Offset Protocols:~~;~~

(A)~~1.~~ Compliance Offset Protocol Livestock Projects, [DATE];

(B)~~2.~~ Compliance Offset Protocol Urban Forest Projects, [DATE]; and

(C)~~3.~~ Compliance Offset Protocol U.S. Forest Projects, [DATE]. (SCPPA8)

Response: We do not agree that ARB offset credits should no longer be invalidated in the event that a second verification is performed on the Offset Project Data Report. The minimum statute of limitations is three years if the Offset Project Data Report or a subsequent Offset Project Data Report, depending on project type, is verified by a different verifier within that time frame. If the offset project does not qualify under these requirements the default statute of limitations is eight years. We do not believe that any time period less than three years would provide sufficient time to detect all relevant new information or uncover any mistakes that verifiers may have missed or may have been unintentionally omitted.

M-56. Comment: The Climate Trust recommends ARB consider developing a fixed ton invalidation threshold for small scale projects for an overstatement of more than five percent under section 95985(c)(1). For a 5,000 ton per year project, an overstatement of 250 tons could trigger a costly review and re-verification process. Setting a minimum threshold of 1,000 tons provides small scale project developers flexibility, while still ensuring there is strong disincentive to overstating emission reductions in an Offset Project Data report. (TCT2)

Response: We did not make this change. The requirements for regulatory verification must be met to ensure that ARB offset credits meet the requirements in AB 32 that all offsets must be verifiable. ARB cannot allow offsets to be used for compliance if they are found to have been issued based on incorrect information, even if it is a very small amount of offsets.

M-57. Comment: IETA greatly appreciates that ARB has extended the period of time that a party has for replacement of invalidated credits from 30 days, then to 90 days, and now to six months. The procedures that are outlined in 95985(d) through (j) are quite involved and will need to be supported by the systems employed by ARB by the start of the program.

Response: Thank you for your support. We will be working to implement the program and all necessary systems once the regulation is finalized.

M-58. Comment: Rather than focusing on liability provisions, ARB rules could be directed towards ensuring offsets should be subject to rigorous verification and certification standards that would eliminate the need to invalidate credits to only the rarest of circumstances. ARB has included appropriate verification and subsequent certification standards to ensure that only quality credits enter the market. If ARB finds it necessary to retain the option of invalidation, a buffer account could be established for all credit categories, similar to the buffer account for forestry projects. Also, compliance entities would have more flexibility to meet the short replacement timeline if ARB allowed the 8 percent for offsets to be used across compliance periods and if a sufficiently large holding limit for allowances is established. The buyer liability approach set out in the draft rules could be more efficient at addressing the problem of invalidated credits. Under ARB's proposed rules, the holder or user of a credit is presumptively liable. If that party is no longer in business, ARB will require the Offset Project Operator or Authorized Project Designee to replace the invalidated ARB credits. The Trust recommends that the Authorized Project Designee be removed from this requirement. The Authorized Project Designee is defined in section 95802(a)(22) as "an entity authorized by an Offset Project Operator to act on behalf of the Offset Project Operator." There are many situations where the Authorized Project Designee only performs limited administration duties and has no influence or control over project outcomes. While ARB has asserted that the various entities can manage their risk through appropriate contracts, the reality is that the credits frequently go through a chain of ownership that would have to be unraveled in order to determine contractual liability upon invalidation. Many medium-sized organizations would avoid these open-ended risks and the market could be composed solely of contracts between large corporations able to bear such liability, thus creating inequity in the market and limiting credit diversity and market participation of medium-sized entities. (TCT2)

Response: This comment was submitted during the first 15-day changes to the regulation. We agreed and removed the Authorized Project Designee from being responsible for replacing invalidated ARB offset credits as part of the second 15-day changes.

We do not agree that we should eliminate buyer liability associated with the invalidation of ARB offset credits. Requiring the user to replace the invalidated offsets ensures that purchasers and users of offset credits do their due diligence in seeking out high-quality offset credits. We have clear enforcement authority over covered entities that will be using ARB offsets for compliance. If the covered entity replaces any invalidated offset credits, they may then take appropriate action through third-party contractual arrangements they may have established prior to purchase. These arrangements currently exist in the voluntary offset market, and we expect that as the offset market becomes more established, that additional mechanisms to deal with the risk of invalidation will also be established. In the event that the offset credit has not yet been used or retired, it will be canceled in the market tracking system and removed from any Holding or Compliance Accounts. These provisions in no way diminish ARB's authority to assess penalties under section 96014 on any offset project developer or verifier that has provided false information to ARB.

The regulation requires that offsets account for eight percent of an individual entity's emissions over a three-year period. We did not allow the carryover of unused offsets within this time frame to ensure that emission reductions are being achieved by capped sources throughout the life of the program. Keeping it to the compliance period allows some flexibility by giving three years to total emissions, but still requires that emission reductions are coming from within capped sectors in all years of the program.

M-59. Comment: Invalidating only the overstated portion of credits when reports overstate reductions by greater than 5 percent fails to create a strong disincentive to offsets developers from purposefully exaggerating the reductions from their projects. We suggest that CARB define a second higher percent threshold whereby overstatements of reductions by amounts over that threshold result in the invalidation of all of the credits generated by the project during that reporting cycle. (UCS8)

Response: The compliance offsets program as a whole is designed to disincentivize offset developers from purposefully exaggerating the reductions from their projects. We do not see this being a problem in the program and believe the invalidation mechanism may not need to be used due to the rigor of the offset provisions. In addition, the purpose of the invalidation mechanism is to ensure that the cap is made whole; therefore, invalidating additional valid offsets is unnecessary.

M-60. Comment: Section 95857(a)(2) (p. 112) states that if the ARB has invalidated offset credits, the compliance obligation for untimely surrender will not apply until 90 days after notice of the invalidation. However, in the revised offset invalidation section of the Regulation, specifically sections 95985(h)(1)(B) (p. 286) and (h)(2)(A) (p. 287), the relevant party is given six months to replace the invalidated offset credits. This longer period should be reflected in section 95857(a)(2) to eliminate the conflict. This change can be made without further 15-day public comment, as it is “nonsubstantial or solely grammatical in nature” for the purposes of section 11346.8(c) of the Government Code. Modify section 95857(a)(2) as follows:

(2) The compliance obligation for untimely surrender (“excess emissions”) will not apply to a covered entity or opt-in covered entity which is determined to have transferred insufficient instruments to meet the compliance obligations of section 95856 solely because of the invalidation of an ARB offset credit by the Executive Officer pursuant to section 95985 until <u>six months</u> ~~90 days~~ after notice of invalidation. (SCPPA8)

Response: We agree and clarified the language. This was a non-substantive change to the regulation.

Reversals in the Forest Sector

M-61. Comment: It is not explicit or clear that liability for submittal of credits to compensate for intentional reversals is limited to the Offset Project Operator, not other Forest Owners. We recommend this section be clarified by replacing “Forest Owner” and “forest owner” with “Offset Project Operator.” (BLUESOURCE3)

> **Response:** We do not agree that the Offset Project Operator should be liable for forest offset invalidations instead of the Forest Owners. We have enforcement authority over all forest owners under the regulation; however, identifying one party as the Offset Project Operator will be more administratively simple for both ARB and the forest owners when dealing with the various offset processes. At least one forest owner will be identified as the offset project operator. Forest owners have physical custody of the carbon stocks, and therefore should be liable for the offset projects. The Forest Owners can establish contractual arrangements among themselves for establishing specific responsibility for invalidated credits.

M-62. Comment: TWS seeks clarification of the mechanics and timing of contributions to the Forest Buffer Pool. Reading section 95983(a)(1) and (2) of the Cap-and-Trade Regulation along with section 7.2.2 and Appendix D of the Compliance Offset Protocol for U.S. Forest Projects (the Protocol), it is unclear whether a forest project makes contributions to the buffer pool only at the time of registry, whether that contribution may be adjusted in the future, or whether a project may be required to make contributions to the Forest Buffer Account after registration. Section 95983(a)(1) and (2) of the cap-and-trade refers to contributions at the time of registration being made in accordance with the Protocol. Section 7.2.2 of the Protocol notes that contributions are made to the Forest Buffer Pool according to a determination of reversal risk determined by requirements and methods in Appendix D of the Protocol. However, Appendix D notes that reversal risk of a forest project is dynamic and recalculated in every year the project undergoes verification. As identified in California’s April 2009, “Indicators of Climate Change in California” report, increased frequency of large wildfires and increased tree mortality are trends occurring in California forests. The risk of unintentional forest offset project reversals (or terminations) is real and may increase over time; and the offset credits in the Forest Buffer Pool are subject to the same unintentional reversals that threaten the permanence of the underlying forest offset projects (although, to the extent there is geographic diversity in the location of registered forest offset projects, that may provide some risk diversification for the Forest Buffer Pool). As the Cap-and-Trade Regulation is currently drafted, it appears that there is no mechanism for replenishing the Forest Buffer Pool after credits are retired to respond to unintentional reversals (and project terminations due to unintentional reversals). Relying on additional contributions to the Forest Buffer Pool from the registration of new forest projects may be an inadequate method of ensuring a Forest Buffer Pool capable of safeguarding the integrity of the emissions cap especially in the face of wildfires or tree mortality events that may affect multiple projects and result in project terminations. Furthermore, in the case of intentional reversals, if ARB is forced to retire credits from the Forest Buffer

Account and to commence an enforcement action, this also creates a risk that the Forest Buffer Account will be depleted and will not have sufficient credits to ensure the integrity of the emissions cap. It is unclear whether any recovery in an enforcement action could be applied to the purchase of replacement credits to replenish the Forest Buffer Account, and even if such replacement credits could be purchased pursuant to a successful enforcement action in an intentional reversal case, there are additional risks and uncertainties created by the disposition of the enforcement action (e.g. the length of time required to secure a successful outcome in an enforcement action, whether bankruptcy or statute of limitation issues may prevent a recovery sufficient to ensure the cap integrity, etc.) If the Forest Buffer Account is depleted and unable to help restore tons to the cap-and-trade program in the face of forest project reversals, then the integrity of the cap-and-trade program may be compromised. ARB could adopt a number of revisions that would help alleviate the risk of depleting the Forest Buffer Account. First, ARB could provide enhanced mechanisms for seeking new contributions to the Forest Buffer Account if the volume of credits in the Forest Buffer Pool falls below a certain percentage of outstanding forest offset credits; possible sources of such replenishment contributions are varied. For instance, the Cap-and-Trade Regulation could require that if the depletion scenario referenced in the preceding sentence occurs, then some or all of the contribution risk ratings in the Appendix D of the Protocol would be accelerated by a specified percentage. In addition to new projects being subject to the accelerated risk assessment, existing projects could also be made subject to a revised risk assessment and additional contribution assessment. For instance, the Cap-and-Trade Regulation could be revised to clarify that existing projects may need to make additional contributions to the Forest Buffer Pool after registration if a depletion scenario arises (which would be analogous to an increased insurance premium based on new information)—and those additional contributions could either come in the form of forest offset credits or other approved compliance instruments. Secondly, ARB could explore the possibility of either using enforcement proceeds associated with the cap-and-trade program to purchase replenishment credits for the Forest Buffer Pool or the possibility of requiring purchase of replenishment credits from defendants in successful intentional forest project reversal enforcement actions. Finally, to better safeguard against depletion, ARB may want to consider broadening the Forest Buffer Pool into a general Offset Buffer Pool and requiring all offset project types to make contributions to an Offset Buffer Pool (with non-sequestration offsets presumably making contributions at a lower rate than sequestration offsets to reflect any lower project risk rating). This broadening of the buffer pool has two potential benefits. First, risk in the buffer pool would be diversified across different types of offset types, but also the buffer pool would then be capable of further bolstering the integrity of the cap-and-trade program by providing a source of credits which ARB can use to make the program whole while pursuing any warranted enforcement actions related to non-sequestration project invalidations. (TWS2)

> **Response:** Forest offset projects must contribute to the Forest Buffer Account each time that the project is issued ARB offset credits in the percentage amount specified in Compliance Offset Protocol U.S. Forest Projects. The amount of offsets that must be contributed to the buffer account is calculated based on a

number of factors beyond just what is needed to account for unintentional reversals, including bankruptcy. We believe that, given the conservative accounting in determining the amount of offsets that must be contributed to the buffer account, no changes are needed in this area. Experience in the voluntary programs has not shown that the buffer pool was at risk for depletion. ARB will monitor this policy and recommend program adjustments as part of future rule-making, if needed.

Early Action

Early Action Operations

M-63. Comment: Section 95990(a) allows the Executive Officer to "qualify" an early action program for offset credits by executive order. However, there is no provision, either in section 95990 nor in subsection 95986(k) regarding ARB Approval of Offset Project Registries, to require an assessment of whether an early action program is consistent with AB 32 requirements. Thus, subsection 95990(a) would seem to allow the Executive Officer to unilaterally approve an early action program, without any assessment of its compliance with the requirements of AB 32 and without adoption by the ARB board. If this understanding is correct, this provision would violate the statutory requirement that the board adopt methodologies for offset credits. Health and Safety Code section 38571 ("The [ARB] board shall adopt methodologies for the quantification of voluntary greenhouse gas emission reductions.") (emphasis added). (CBD5)

> **Response:** We disagree that the requirements for approval of Early Action Offset Programs and early action offset credits in section 95990 do not meet the requirements of AB 32. First, Early Action Offset Programs must be approved as Offset Project Registries, and if they do not wish to act as an Offset Project Registry, we included specific provisions that these programs must meet in section 95990(a) to ensure the rigor of the program. The interpretation of the language by the commenter is not accurate. The regulation does not allow all credits issued by the Early Action Offset Program to be used in the program. Any early action offset credits that are allowed in the program must be issued by a program approved pursuant to section 95990(a), and must meet the rest of the lengthy requirements in section 95990—including that they be developed under protocols that are specifically listed in section 95990(c)(5). These project types have been approved by the Board as part of the cap-and-trade rulemaking and have undergone a programmatic environmental analysis as part of ARB's rulemaking process. In addition, the early action offset credits must meet the requirements for regulatory verification pursuant to section 95990(f) and must be issued by ARB after we review the verification assessment by an independent ARB-accredited verifier. We believe that given all of these requirements, any early action offset credits used in the program will meet the criteria in AB 32.

M-64. (multiple comments)
Comment: ARB has specified the timing for auctions in 2012 but has not provided any timelines for the registration of early action offset projects. A definitive timeline would help all parties to better plan and contract for offset deliveries and allow time to identify and resolve any bottlenecks in the approval process. (IETA4)

Comment: ARB has specified dated for when the first auctions will be created. ARB should consider specifying a date when the first compliance offsets can be created. (CIG3)

> **Response:** ARB has provided a role for Offset Project Registries (OPR) to perform some of the administrative functions of the offset process in the regulation. ARB plans to utilize OPRs in lieu of performing these duties itself in the short-term, and may choose to continue this throughout the program. ARB has not yet determined if and when it would itself perform these roles. Therefore, in the meantime all parties seeking to use Compliance Offset Protocols must go directly to an OPR to list their projects. ARB is in the process of developing the training for OPRs, and plans to approve OPRs sometime in 2012. In addition, we are in the process of developing the training for offset verifiers and plan to accredit offset verifiers in 2012 as well. Once these mechanisms are in place, ARB and registry offset credits can be issued.

Early Action Offset Supply and New Early Action Protocols

M-65. (multiple comments)
Comment: VCSA notes that, with the exception of the placeholder language in section 95990 regarding early action offsets, the modified draft rule still limits the number of offset protocols eligible for use in the California cap and trade program to the four project types already approved. Such a limitation places an unnecessary constraint on the market, stifling innovation, creating uncertainty among project developers and investors, and ultimately limiting the cost containment benefits that offsets offer to a cap and trade system. There exist a number of established carbon offset standards that have significant standing in the domestic and international carbon markets that stand as ready sources of protocols for ARB's consideration. ARB should initiate an open, transparent process for evaluating and approving protocols from established, high quality carbon offset standards prior to the 2013 implementation of the cap and trade program. (VCSA2)

Comment: VCSA is pleased to see that the criteria for approval of early action offset credits issued by early action offset programs in section 95990(c) now includes a place holder for GHG reductions or enhancements that result from the use of "additional early action offset project protocols" (i.e., protocols other than the four protocols already approved by ARB). Expanding the list of eligible protocols will encourage more projects to seek credit for early action and, as a consequence, will enhance liquidity and help contain the cost of compliance early in the program. This is especially important given the possibility that the supply of offset credits issued under the four approved protocols may not meet demand. However, the modified draft rule does not identify a mechanism for how additional protocols will be considered and added to the list of existing eligible early action methodologies. To truly facilitate the development of an adequate pool of early action credits, more clarity must be provided for how early action protocols can be brought forward for consideration and approval. Amend section 95990 to include a provision that describes a transparent process that ARB will employ to receive, evaluate and approve additional early action offset protocols. (VCSA2)

Comment: The phrase "offset quantification methodologies and relied on the most recent version thereof at the time of offset project submittal" in (c) (5) should be clarified. We see a potential issue from the language as proposed since it is not obvious that the most recent version refers to the time the project was first submitted to the voluntary registry, or the time at which the project is submitted to ARB for recognition as an early action credit. We presume that ARB intends, where there are multiple versions of an approved protocol, that the most recent version of the protocol is the one by which the offset project is to be quantified, not to an earlier version. The staff memorandum is clearer on this point, since it states "only the most current version of any protocol may be used at the time the project is initiated." We recommend that the "initiation" concept be included expressly in (c) (5). This intent further demonstrates that later versions of a recognized protocol are not to be applied to a project which was submitted under an earlier protocol. Of course, this is exactly the conclusion we urge ARB to reach with respect to ODS methodologies. One can trace the involvement of early actors from the CCX ODS protocol to the CAR ODS protocol. (GEAG2)

Comment: The CCX ODS Protocols 1.0 and 2.0 should be added to the list of approved methodologies in (c) (5) following (c) (5) (D). The CCX was the first voluntary registry to adopt an offset protocol for ODS materials. The CCX ODS Protocol resulted from a combination of environmental agencies, industrial sources, project developers, consultants, verification bodies and investors and represented the best thinking at the time with respect to offset credits for ODS destruction. Many of these same parties then became involved in the efforts by the Climate Action Reserve to develop its ODS protocol, now proposed to be recognized by ARB as a valid protocol for early action credits [see 95990 (c) (5) (C)]. By virtue of the way ODS projects are undertaken, only projects initiated in anticipation of the CAR Protocol, released on January 22, 2010, would qualify under the early action rules as proposed. This request thus represents the classic case for recognition of early action. It is critical that ARB recognize the principle that early reductions provide great value, and perhaps even greater value to the climate than reductions which are achieved later. If sources, developers and investors are uncertain that their early reductions, undertaken in good faith, voluntarily and using the most current scientific methodologies, will not be counted or not have value, that will substantially slow the pace of innovation and emission reductions. As is the case with almost any offset protocol, changes occur over time; indeed, if there were no need for improvement, Protocols would not likely be changed. But that does not detract from the environmental benefits of early action, particularly with respect to climate change issues. It is well accepted in the climate change science that earlier reductions provide greater value—by reducing emissions earlier—than later reductions of an identical quantity. Therefore, it would be unfair to make a rule whereby ODS offset credits issued under the CCX protocol have no value, destroying the expected value for the efforts and investments made simply because of the differences between the CCX ODS Protocols and those developed later by the Climate Action Reserve. Thus, both Version 1 and 2 of the CCX ODS Protocol were developed and then adopted following comments and reviews by a wide variety of stakeholders. (GEAG2)

> **Response:** In regard to additional early action offset protocols, this comment falls outside the scope of the second 15-day changes notice; therefore, no further response is required. Responses to similar comments can be found in this category under the 45-day comment responses.

Early Action Offset Project Transition

M-66. Comment: With regard to the buffer account for forestry projects, it appears the buffer is to be composed of the full vintage year of credits, not taking into account credits that were already retired. CERP seeks clarification on whether this was ARB's intent, and if so, why such reductions should not be taken into consideration in some way. The buffer based on full vintage years will increase the number of credits needed. CERP suggests that in the next rulemaking ARB should alter the regulations such that when determining the percentage of tons that must be added to the buffer account, ARB should subtract tons that have already been retired. (CERP5)

> **Response**: The buffer account will transition to ARB and apply to early action credits for which ARB issues offset credit and for the voluntary credits that do not transition over. For example, if there is a reversal for voluntary credits from the 2004 vintage year, the voluntary registry would notify ARB, and ARB would retire buffer credits from the pre-early action vintages to make the voluntary program whole. In discussions with the voluntary registry, it was decided that ARB would take all of the credits associated with a project that transitioned to ARB and would administer it for any pre-early action vintages as well.

M-67. Comment: CERP requests that ARB include a timeline when the infrastructure for such transitioning will be available in the Final Statement of Reasons. Put another way, we would like to know the earliest date a project could transition to a Compliance Offset Protocol. The addition of a timeline will give contracting parties a better ability to plan for the transition to compliance projects in their credit transactions. (CERP5)

> **Response:** Once ARB Compliance Offset Protocols are finalized in October 2011, project developers will be able to use them to quantify, monitor, and report their GHG reductions and GHG removal enhancements. In 2012, ARB will approve additional Offset Project Registries so that project developers can list and report their emissions with these registries. We will also accredit ARB offset verifiers in 2012 to verify GHG reductions and GHG removal enhancements from offset projects developed under Compliance Offset Protocols.

M-68. Comment: The rules for recalculating baselines for projects under CAR Forest Project Protocol v.2.1 upon transition to the ARB Offset Protocol are difficult to follow. For example, section 95990(k)(1)(D) states that "....Registry offset credits and ARB offset credits issued for the first Reporting Period after the early action offset project is listed pursuant to section 95975 using the Compliance Offset Protocol U.S. Forest Projects, [DATE], will only be for the increased carbon stocks beyond what was already issued early action offset credits in the last year before the early action offset project transitioned to a Compliance Offset Protocol pursuant to this section." It is unclear what happens to a project transitioning to a Compliance Offset Protocol pursuant to this section if there are fewer ARB credits available upon transition than were already issued as early action credits under the early action project baseline. Clarification of this and other baseline calculation issues are essential to enable Offset Project Operators to accurately evaluate the consequences of listing and/or transitioning their projects. (TCF3)

> **Response:** The language is to clarify that the first year a project transitions to the ARB Compliance Protocol and recalculates its baseline, the first time credits are issued by ARB under the Compliance Protocol, they do not overlap with any credits that were issued under the voluntary program under the previous baseline conditions. ARB will develop guidance documents as part of program implementation.

Transitioning Early Action Offset Credits to ARB Offset Credits

M-69. Comment: The process set out in the rules for transitioning early action credits to ARB verified offsets remains burdensome. Section 95990(d) could be modified to allow holders or owners of early action credits to register with ARB in addition to Offset Project Operators and Authorized Project Designee. Section 95990(k) could be modified to include a defined and sufficiently long period under which eligible early action projects can transition to ARB Compliance Offset Protocols. An unclear window of time creates the risk that otherwise credible projects may no longer supply the market. The Trust recommends ARB establish a definitive transition period in which eligible early action projects can make the transition to ARB. A sufficiently long and clearly communicated transition period, such as January 1, 2014 through December 31, 2015, will ensure flexibility as registries receive and implement ARB requirements. (TCT2)

> **Response:** We disagree that we should allow both project operators and holders to register with ARB for an individual offset project. The regulation is designed to incentivize early action offset project operators to transition their projects to ARB for administrative simplicity and enforceability reasons. While our preference is that the project operator bring the project into the compliance program, we recognize that some stakeholders have concerns that early action offset project operators will not do so, and they would therefore hold early action offset credits that could not come into the program even though they meet the requirements. For this reason, we added a back-up mechanism to allow the

individual holders of the credits to register with ARB and transition early action offset credits into ARB offset credits.

We believe that the new requirements provide sufficient time to transition to Compliance Offset Protocols. According to the regulation, the early action offset project may transition to a Compliance Offset Protocol any time before February 28, 2015, but must list or register with an Early Action Offset Program by January 1, 2014 (section 95990(c)(3)). We removed any requirements that restrict the earliest date that early action offset projects must transition to Compliance Offset Protocols. It is necessary for offset projects beginning February 28, 2015, to transition to Compliance Offset Protocols to ensure consistency in the program, and that all offset projects are following the rules of the regulation, including the rules in the Compliance Offset Protocols.

M-70. (multiple comments)

Comment: The registration, listing and issuance requirements in sections 95990(d), (e) and (h) seem to allow for a holder of early action offset credits to list, register and be issued ARB offset credits for a forestry project if the Early Action Project Developer does not list or register the project. This seems inconsistent with the summary accompanying the rules which states that: "New sections 95990(d)(1), (e)(1)(A), and (h)(5)(A) were added to clarify that Offset Project Operators or Authorized Project Designees for forest and urban forest offset projects that do not transition their early action offset projects to Compliance Offset Protocols must register with ARB for issuance of ARB offset credits. For these projects, the holders of the early action offset credits may not register, list, meet the attestation requirements, and seek issuance of ARB offset credits. Staff is requiring the project proponents to register in these cases to ensure that the CO_2 sequestered and credited by ARB remains sequestered and ARB has enforcement authority in the case of reversals from these projects." Holders of early action offsets from forestry projects should not independently be allowed to register or list an early action project or seek issuance of ARB offset credits. We recommend that the rules be clarified to conform to the statement in the summary. (TCF3)

Comment: PFT is concerned with the lack of clarity in section 95990(d) with regards to situations under which holders of credits from potential early action forest projects may list a forest project. Language in (d)(3) appears to indicate that only when a forest project operator transitions to the ARB Compliance protocol but has not registered the project for prior early action credits can a credit holder, as opposed to the project operator, list the same project for early action credits. However, there remain different interpretations of this sub-section in the project developer community. We request full clarification of the intent of this section as soon as possible, and request that credit holders not be given the ability to list forest projects under broadly defined circumstances, but only in the event that a project does transition to the compliance protocol, and has not listed the project for early action credits. (PFT4)

Response: We disagree that the holders of offsets from forest projects should not independently be allowed to seek issuance of ARB offset credits, and did not make this change. The regulation is designed to incentivize early action offset project operators to transition their projects to ARB for administrative simplicity and enforceability reasons and also seek issuance of early action offset credits for the purchasers and holders of those credits. If the project operator transitions the project to a Compliance Offset Protocol but does not want to seek early action offset credits, we believe the holders of the voluntary credits should be able to seek issuance, if the credits meet all of the requirements of section 95990. We encourage Offset Project Developers to work with the purchases of offset credits generated for their projects to transition them into ARB offset credits. The regulation is designed that if the project operator seeks issuance of early action offset credits, then the holders cannot. In this case, preference is given to the operator, for reasons mentioned above.

M-71. Comment: IETA still has concerns that the process for accrediting early action credits and transitioning them to ARB-certified offsets continues to be unreasonably burdensome. Specifically, New sections 95990(h)(6)(A), (B), and (C), still require the Offset Project Operator, Authorized Project Designee, or each holder of the early action credit seeking issuance of ARB offset credits to cumbersome processes for attestations. Again, while IETA understands these sections relate to ARB efforts to make early action offsets undergo consistent post-issuance provisions compared with compliance offset credits, holders of early action offsets cannot make the attestations outlined as these elements are beyond their control; and they will need to come under the purview of the original project verifier and ARB appointed verifier instead. IETA also notes ARB provided additional clarification to the provisions dealing with the conversion of forestry offsets to ARB early action offset credits. The newly modified draft rule, however, still does not identify a mechanism for how additional protocols will be considered and added to the list of existing eligible early action methodologies. To truly facilitate the development of an adequate pool of early action credits, IETA again suggests more clarity must be provided for how these early action protocols can be brought forward for consideration and approval. IETA recommends ARB amend section 95990 to include provisions for a transparent process that ARB will employ to consider, evaluate and approve additional early action offset protocols. (IETA4)

Response: We modified section 95990 to streamline the process for transitioning early action offset credits into ARB offset credits that can be used for compliance. This includes allowing holders/current owners of early action offset credits to transition them into the compliance program if the project developers do not do so in most cases. We did not eliminate the attestation requirements; however, we did make minor modifications to the wording of the attestations. These attestations are necessary to ensure ARB's enforcement authority and the integrity of the system.

In response to additional protocols this comment falls outside the scope of the second 15-day changes to the regulation; therefore, no further response is required. Responses to similar comments can be found in this category under the 45-day comment responses.

M-72. Comment: Section 95990(i)(1)(D)(3) states that ARB offset credits will be issued to the Offset Project Operator. This procedure creates three problems:

1. The Offset Project Operator cannot definitively establish which of its early action offsets are ineligible for ARB offset credits because they have been "retired, canceled . . . or used to meet any GHG mitigation requirements in any voluntary or regulatory system" as specified in section 95990(h)(7);
2. It puts the Offset Project Operator in the position of receiving and then transferring the ARB offset credits to the various holders of the early action offsets. Not only does this raise the issue of ownership and possession of the ARB offset credit, it also assumes that project developers are capable of competently and fairly administering the transfer; and
3. For early action projects developed under CAR Forest Project Protocol version 2.1, this section assesses the buffer contribution against the Offset Project Operator, thereby imposing a cost on the Offset Project Operator that should rightly be imposed on the holder if they want to receive an ARB offset credit. The holder of the early action offset got what it paid for—a CRT issued by CAR. If they want an ARB offset credit, they should cover the additional cost attendant to the buffer pool requirement.

These concerns can be readily addressed by having the "issuance" of an ARB offset credit consist of ARB posting the serial numbers of the accepted early action offsets in exchange for which ARB is prepared to issue an ARB offset credit. That way, each holder could then present their early action offsets and received its ARB offset credits after ARB deducts the appropriate buffer amount AND the holder attests that the early action offset has not been retired or used in another program. (TCF3)

Response: In regard to point 1, we do not believe that is necessary for the Offset Project Operator to make this distinction. We will only issue ARB offset credits for serial numbers of those early action offset credits that meet the requirements of this section. We will work with the Climate Action Reserve to determine which offset credits have already been retired.

In regard to points 2 and 3, we understand your concerns. We encourage offset project developers to work with holders of early action credits in good faith to transition their early action credits to the ARB program. We do not believe the buffer pool issue will be that significant as the voluntary program will release any contributions from the buffer pool in the voluntary program to ARB. We will work with stakeholders during implementation and, if needed, recommend changes as part of future rulemaking.

M-73. Comment: CERP suggests that ARB use the Final Statement of Reasons as a vehicle to clarify how the individual credit holder system will function. Some questions to be considered include:

- Will a number of different credit holders be able to submit paperwork?
- What if one verifier for one credit holder finds that it agrees with "reasonable assurances" that the initial verification was correct during the desk review, and another finds that a full verification should be required?
- How will ARB deal with discrepancies between paperwork generally?
- How will credits move between project developer and individual credit holder? (CERP5)

  Response: Each credit holder seeking issuance of ARB offset credits must submit the information required in section 95990(e)(2). If there is a discrepancy in the paperwork submitted, ARB will work with the holders and Early Action Offset Program to resolve the discrepancy. Our preference is that one regulatory verification will be performed for each Offset Project Data Report and that the Early Action Offset Program or the Offset Project Operator will facilitate this verification for all credit holders so that ARB only receives one verification opinion. On the last question, we will develop guidance documents as part of implementation or, if needed, recommend changes as part of a future rulemaking.

M-74. Comment: We believe the language in section 95990(d)(3) causes confusion in that project operators have until February 28th, 2015 to transfer their projects to the compliance protocol. The existing language seems to allow for the possibility of a credit holder listing a project prior to the forest project operator having made the final decision or actually taken the action to transition their project to the compliance protocol. We request that this sub-section be clarified to mean that the holder of potential early action credits cannot list the project until AFTER the project operator actually has transitioned to the compliance protocol. (PFT4)

> **Response**: We designed the program to incentivize and streamline the process for early action offset project operators to transition their projects to ARB. Early action offset credits may not be issued until the offset project lists with ARB, so that we can be certain of the decision to transition the project to a Compliance Offset Protocol.

M-75. Comment: ARB has introduced regulations that address the requirement that forestry owners register with ARB unless they are certain to be joining the compliance program. CERP understands that ARB must at all times have a continual link to a forestry project for permanence reasons, however notes that it is onerous for the entities involved in a forest project to be required to decide for certain in 2012 whether it is going to transition to a compliance protocol in 2015. (CERP5)

Response: We are unclear as to which 2012 deadline the commenter is referring. According to the regulation, the early action offset project may transition to a Compliance Offset Protocol any time before February 28, 2015, but must list or register with an Early Action Offset Program by January 1, 2014 (section 95990(c)(3)). We removed requirements that restrict the earliest date that early action offset projects must transition to Compliance Offset Protocols. Early action offset credits may not be issued until the offset project lists with ARB, so that we can be certain of the decision to transition the project to a Compliance Offset Protocol.

M-76. Comment: Many owners of early action forest projects will be unable to transition their projects to ARB. Large volumes of otherwise ARB-compliant offsets, registered under ARB-approved protocols and registered with ARB-approved Early Offset Programs, will therefore be excluded from the compliance market. This is because holders of these credits will be unable to independently apply for ARB Offset Credits under the terms of this section. This is an unnecessary constraint as any risks associated with these offsets can be mitigated by other means. We recommend that the holders of credits verified under ARB-approved Early Offset Programs should be issued ARB Offset credits subject to that holder's assumption of all responsibility for regulatory verification requirements, as well as future invalidations and reversals not compensated for by the Early Offset Program's risk mitigation approach. (BLUESOURCE3)

Response: We disagree that many forest offset projects will not be able to transition to Compliance Offset Protocols. We designed the program to incentivize and streamline the process for early action offset project operators to transition their projects to ARB. If the operator transitions to a Compliance Offset Protocol, the holders of early action offset credits will be able to bring them into the program.

M-77. Comment: Section 95990(h)(5)(A) removes the ability for a holder of forestry EAOCs to submit these to ARB to receive ARB offsets. There have been numerous transactions where forest owners have sold offsets to intermediaries that can no longer be used for compliance unless the forest owner signs the attestation. Since the transaction has already taken place, the forest owners are under no obligation to sign the attestation and the buyer cannot receive credit for early action which is one of the principles of the ARB process. We recommend that ARB allow holders of forestry EAOCs to submit these to ARB and receive ARB offsets without the forest owner signing the attestation. The holder should be held liable for replacing invalidated offsets. (FINITE2)

Response: Offset Project Operators or Authorized Project Designees for forest and urban forest offset projects that do not transition their early action offset projects to Compliance Offset Protocols must register with ARB for issuance of ARB offset credits. For these projects, the holders of the early action offset credits may not register, list, meet the attestation requirements, and seek issuance of ARB offset credits. We are requiring the project proponents to register in these cases, to ensure that the CO_2 sequestered and credited by ARB remains sequestered and that ARB has enforcement authority in the case of reversals from these projects. If the Offset Project Operators or Authorized Project Designees for forest and urban forest offset projects do transition their early action offset projects to a Compliance Offset Protocol, we are allowing the holders of these credits to take actions for these early action offset projects because there is no risk of reversal for those offset projects. If the forest or urban forest offset project is transitioning into the compliance offset program, ARB can monitor and address reversals in the future because the Offset Project Operator or Authorized Project Designee will be part of the compliance offset program.

M-78. Comment: In previous public comments, Evolution Markets advocated for regulatory changes to streamline the process for the conversion of early action offset credits (EACs) to ARB-issued offsets. Reducing the administrative burden and simplifying the conversion process will bring more offsets into the system in the early years of the program, where their cost containment benefits can be fully realized. ARB's most recent round of proposed changes take important steps to effect this streamlining of the system. These include:

1.) Holders of Allowances Permitted to Manage Conversion Process: New language proposed by ARB will allow the holders of EACs, in addition to project operators and authorized project designees, to register projects for conversion. This provides credit buyers the ability to manage the conversion process without relying solely on the project owner, and Evolution Markets supports this rule change.
2.) Streamlining of Desk Review: The desk review of EACs submitted for issuance as ARB offsets has been streamlined by requiring the verifier simply review the verification statement for issuance under an approved early action protocol and eliminates a threshold of a 3% material misstatement as a trigger for full re-verification. Evolution Markets believed that the 3% level would have created an unnecessarily large amount of reviews, which could impede the generation of an early supply of credits. The newly proposed process will maintain environmental integrity of the program, while ensuring a process for adequate offset supply.
3.) Create Accreditation Program for Project Verifiers As Soon As Possible: An important factor in ensuring a sufficient supply of early action credits for use in compliance will be the availability of verifiers. A lack of verifiers not only has the ability to restrict supply but introduces an element of uncertainty in the timing of credit supply that has corresponding price risk for compliance buyers of offsets. Evolution Markets has encouraged ARB in the past to create the accreditation program for project verifiers as soon as possible.

ARB has recognized this need, and staff has indicated that this program will begin in earnest at the conclusion of the rulemaking process. Evolution Markets continues to recommend ARB make the creation of the accreditation program for verifiers a priority upon the completion of this set of rule changes. Efforts to establish the accreditation program and initiate the accreditation process will allow holders of qualifying offsets to begin the process of conversion to ARB offset credits in advance of the onset of compliance obligations, ensuring a robust early supply of offsets to be used as a cost containment mechanism. (EVMKTS3)

> **Response:** Thank you for your support. The verifier and verification body accreditation program established in the MRR for purposes of emissions reporting will be expanded to include the accreditation of verifiers and verification bodies for offsets. We are in the process of developing the training for offset verifiers, and plan to accredit offset verifiers in 2012.

Regulatory Verification of Early Action Offset Credits

M-79. Comment: CERP again recommends that ARB change the regulations so that an original verification by an ARB-accredited body is adequate, provided that the body attests to the accuracy of its verification. (CERP5)

> **Response:** We did not make a change to the requirements for independent review. The commenter’s suggestion is contrary to the basic premise that an offset project be subject to an internal independent review, to ensure that the verification process and findings are appropriate for the offset project.

M-80. Comment: We urge ARB to go further to provide smaller-scale projects increased flexibility by, for example, not requiring smaller-scale early-action projects undergo a costly review and possible re-verification and setting the threshold for invalidation of emission reductions generated by these projects to a minimum of 1,250 (5 percent of 25,000)—avoiding a situation where a project has to undergo a full re-verification costing over $10,000 for a small number of emission reductions. Limiting the Statute of Limitations provisions further for projects generating less than 25,000 would also stimulate demand amongst buyers to support smaller-scale project and lower costs for project developers. (CIG3)

> **Response:** We modified section 95990(f) to clarify the requirements for regulatory verification of early action offset projects. New section 95990(f) includes new requirements for regulatory verification that is intended to streamline the process and minimize costs associated with converting the voluntary offsets into compliance offsets that can be used for compliance.
>
> AB 32 requires all offset credits used for compliance purposes to be subject to regulatory verification, and ARB cannot rely on a non-regulatory program to perform regulatory verification of offsets that will be used for compliance. AB 32 requires that all offset credits used for compliance be based on the result of regulatory verification.

M-81. Comment: For clarity, revise section 95990(f)(1)(B) as follows:

(B) "Review of the data checks conducted by the offset verification body for the Early Action Program to ensure they were calculated ~~correctly;~~ <u>in accordance with the applicable offset quantification methodology.</u> (TCF3)

Response: We will consider this request in a future rulemaking as we continue to evaluate how to make these provisions more clear.

Sector-Based Crediting

M-82. Comment: Sector based offsets should not be limited to the U.S., Canada and Mexico in section 95991. Modify section 95991 as follows:

Sector-based offset credits may be generated through reduced or avoided GHG emissions from within, or carbon removed and sequestered from the atmosphere by a specific sector in a particular jurisdiction. The Board may consider for acceptance compliance instruments issued from sector-based offset crediting programs that meet the requirements set forth in section 95994 and originate from developing countries or from subnational jurisdictions within those developing countries~~, except as specified in subarticle 13.~~ (CCEEB4)

Response: We did not make the suggested edit. This comment is premature, and is best addressed when ARB considers REDD credits.

Air District Comments Regarding Offsets

M-83. Comment: The regulation still contains restrictions that an organization cannot perform multiple roles. SCAQMD may wish to run an offset registry, but this is currently precluded in Section 95986, which has a requirement that to be an Offset Project Registry, it must be the organization's primary business. Further, an organization that runs a registry cannot perform many other functions related to offsets, such as run projects or verify offsets. As detailed in previous correspondence from CAPCOA, in the August 11, 2011 comment letter from SCAQMD and in briefing materials prepared by SCAQMD staff for Secretary Linda Adams (November 9, 2010) and Ms. Nichols (December 9, 2010), SCAQMD supports the previously requested language from CAPCOA. The following language will allow SCAQMD and other air districts to administer offset registries. Add section 95989 as follows:

<u>Section 95989. California air pollution control districts or air quality management districts Notwithstanding any other provision of this regulation, California air pollution control districts or air quality management districts may be approved for multiple roles, including verification for mandatory reporting or offsets, holding compliance instruments, implementing offset projects that are verified by a third party and approved by CARB, and running a Registry, provided the appropriate training, certification, or approvals are obtained from CARB. Decisions on such approval requests will be provided in a timely fashion.</u> (SCAQMD5)

Response: Air districts are able to participate in the cap-and-trade program, but they must meet the eligibility and conflict-of-interest requirements in the regulation for whichever role(s) they decide to take. The cap-and-trade regulation provides for distinct roles within the compliance offset program. The roles include project developers, offset verifiers, and approved offset project registries. There is a careful separation of roles for offset project developers, verifiers, and registries to keep in place a system of independent checks and balances throughout the whole offset system. This parsing of roles is consistent with international standards and best practices, as well as program elements developed within the Western Climate Initiative, and applies to all participants (private and non-private) that choose to be part of the compliance offset program.

In Resolution 11-32, the Board directed the Executive Officer to partner with the air quality management districts and air pollution control districts in the implementation of the cap-and-trade regulation, including, but not limited to, an evaluation of the impacts of the cap-and-trade program on industrial source greenhouse gas permitting and implementation of the Adaptive Management Plan. The Board further directed the Executive Officer to report back periodically to the Board on the nature and extent of this partnership with the first report due in the first quarter of calendar year 2012.

M-84. Comment: We commend the changes made to resolve the previous conflict of interest requirements preventing Air Districts to act as verifiers within their own jurisdiction and support CARB staff for their work on the development of this regulation. (SCAQMD5)

Response: Thank you for your support.

Tribal Lands

M-85. Comment: The definition of "Tribe" has been broadly expanded to include "any entity" created by a Tribe. This definition could mean virtually anything according to the definitions, and affects offsets protocols. This change is so broad that we can only imagine the potential effects, which are quite negative. We didn't see any evaluation supporting such a change. This is very troubling since there is a trend toward siting harmful entities on tribal lands, which are frequently contested by tribal members, but approved by tribal governments. CARB should not be in a position of encouraging use of tribal lands for potentially harmful activities. Many tribal members are fighting new and major pollution sources on tribal lands in the U.S. and are fighting their own tribal governments, which, like other local governments in the U.S., sometimes rubber-stamp heavy development projects without full review. The effect of CARB setting such broad definition changes listed above might even allow a nuclear power company to be considered a "Tribe" under this provision or allow "clean" coal projects. The added language on "any entity" should be struck entirely. (CBE3)

Response: ARB disagrees with the commenter that "any entity" should be struck and has not made this change. The commenter cites to "trends" without any factual support, so ARB is not able to more fully respond to the comment. ARB has sufficiently justified all changes made to the regulation and incorporated protocols. The word "Tribe" in the regulation only relates to offset projects under approved offset protocols. The commenter seems to be extrapolating this definition to imagined negative impacts from increasing industry around tribal areas, which is a concern that is broader than the context of the regulation or offsets. The added language was included to ensure that any limited waiver of sovereign immunity by a Tribe would include entities created by Tribes within the waiver—i.e., so an entity created by a federally-recognized Tribe would not be able to assert a sovereign immunity defense to any ARB action.

M-86. Comment: TWS appreciates the language ARB has added in the Forest Protocol and the Second 15-day Change Notice to clarify the eligibility of Tribal lands for reforestation and improved forest management programs. (TWS2)

Response: We appreciate the support.

Other Offset-Related Comments

M-87. Comment: Regulated entities should be allowed the flexibility of banking unused offsets on a year-to-year basis. (CALCHAMBER4)

Response: Section 95922(c) establishes that ARB offset credits do not expire unless retired or surrendered to meet a compliance obligation.

M-88. Comment: CERP seeks assurances that the new language in section 95971(b) will not override the critical principles in other parts of the regulation that: (1) revision of a Protocol shall not affect the validity of credits already issued under the original version of that Protocol; and (2) any offset project shall be subject to the version of a Compliance Offset Protocol in effect when its crediting period began for the duration of that crediting period. CERP requests that ARB clarify these principles in the Final Statement of Reasons. (CERP5)

Response: It is our intent that an update to a Compliance Offset Protocol will not affect the validity of credits issued under an earlier version, and that an offset project may continue to use the version of the Compliance Offset Protocol that was in effect when its crediting period began for the duration of that crediting period.

M-89. Comment: VCSA notes that section 95972(a)(9) of the modified draft regulation text has been redrafted to clarify "standardized methods." VCSA has recently issued for public comment draft requirements for two specific approaches for standardizing the determination of baselines and additionality. The two methods are performance methods and activity methods. Performance methods set performance benchmarks, or metrics, for determining additionality and/or the crediting baseline. Project activities that meet or exceed a pre-determined level of the performance metric (e.g., a given level of CO_2e emissions per unit of output) may be considered additional, provided they also meet other qualifying criteria). A performance benchmark can also serve as a baseline for crediting GHG emission reductions and removals. Activity methods use a positive list to pre-determine additionality for given classes of activities. Project activities may qualify for a positive list if they are not financially viable without carbon finance, have no revenue streams other than carbon finance, or have low rates of adoption in the marketplace. An activity that qualifies for a positive list is automatically deemed to be additional. The draft requirements are the product of a VCS-convened expert committee comprised of individuals representing a broad range of stakeholders knowledgeable in the effective functioning of GHG programs including methodology and project developers, environmental non-profit organizations, GHG program regulators, validation and verification bodies, and businesses. VCSA would be happy to schedule a briefing specifically for ARB staff to discuss the relevance and applicability of its work on standardized approaches to the California offset program design. (VCSA2)

> **Response:** We understand the methods for determining additionality and establishing baselines. We believe that the process and methods established in the regulation reflects the most accurate and efficient way to establish additionality. Our offsets program is designed to rely on standardized assessments of additionality established by ARB through a public process.

M-90. Comment: We recommend adding the words "and Review" to the title of section 95971 to reflect the addition made to that section. Modify section 95971 as follows:

> section 95971. Procedures for Approval <u>and Review</u> of Compliance Offset Protocols. (UCS8)

> **Response:** We did not make this change. We believe the intent of the provisions in this section are clear.

M-91. Comment: TWS continues to urge caution with respect to any further efforts to make federal lands eligible to generate offset projects for the California cap-and-trade program. As we noted, in our August 11, 2011, comment letter on the California Cap-and-Trade Regulation, any commitment of federal land agencies to manage for increased carbon sequestration, and especially participation of these agencies in private offset markets must be consistent with their broad public mission and fully protect other public benefits. A thorough public and scientific review is necessary to develop a cohesive national policy regarding the appropriateness of use of federal lands in any offset program. As an attachment to this letter, TWS submits for ARB's consideration a January 2010 letter from six national environmental organizations to the U.S. Department of Agriculture and the U.S. Department of the Interior, further outlining potential issues associated with offsets on federal lands. (TWS2)

Response: Federal lands are not eligible to participate in the offset program. We understand the challenges that are involved in applicability of the program to federal lands and will continue to monitor the issue. Any future decision to allow offset projects on federal lands would be part of a full rulemaking, including a stakeholder review process.

M-92. Comment: PG&E is concerned about reducing the percentage of sector-based credits allowed in the second compliance period. Reducing the use of sector-based offsets from 50 percent to 25 percent will put strain on an already limited market. PG&E's analysis shows that supply will only be approximately 60 percent of the allowed supply in the first compliance period, even if the pneumatic controllers, rice cultivation, and fertilizer management protocols are adopted early next year. PG&E expects more significant shortfalls in the second and third compliance periods, absent adoption of additional protocols. (PGE5)

Response: We recognize stakeholder concerns regarding offset supply. ARB is prohibited from adopting additional protocols as part of this cap-and-trade rulemaking. All offset protocols used in the compliance program must be adopted by the Board after undergoing a full regulatory process, including an ARB stakeholder process, in accordance with the Administrative Procedure Act, and an environmental review. We plan to look at further offset protocols for potential inclusion in the cap-and-trade program beginning in 2012. The details surrounding any new offset project types for which ARB adopts an offset protocol will be dealt with under that specific rulemaking, and modification will be made to the cap-and-trade regulation as needed.

We will continue to evaluate whether the four project types already approved for use in the program could be expanded to apply to projects located in the United States, U.S territories, Canada, and Mexico. Any changes to the already adopted protocols will be done as part of a separate rulemaking process to ensure that the GHG reductions and GHG removal enhancements being credited as offsets are real, additional, quantifiable, permanent, verifiable, and enforceable.

N. PROTOCOLS

Forestry Protocol

Clearcutting

N-1. Comment: CARB did not provide an analysis of the environmental impacts of clearcutting the forests providing offsets after 100 years. CARB should calculate the maximum emissions increase that could occur, and other environmental impacts that could occur with such clearcutting at the time of expiration at 100 years. (CBE3)

> **Response**: Any GHG reduction or removal for sequestered carbon that is issued an offset credit by ARB will need to be maintained for the period of 100 years. While the existing cap-and-trade program is initially set to continue through 2020, ARB has a designed a program that can and is expected to continue in operation well beyond that year. There is nothing provided by the commenter to substantiate that any sequestered carbon stocks would automatically be subject to clearcutting after the 100-year commitment has expired, and depending on the end fate of any harvested forest, some wood use, such as furniture, may continue to sequester that carbon.

100-Year Offset

N-2. Comment: The forest protocol requires landowners to continue to monitor, verify and replace all carbon lost through reversals for 100 years following the last issuance of credits. This requirement currently exists in the voluntary market and has regularly been cited as the primary reason impeding forest carbon project supplies. As such, ARB offset supply projections from the forest sector should expect severely limited forest carbon supplies in the compliance market if a more flexible permanence period is not possible. (TCT2)

> **Response:** We did not reduce the period for ensuring permanence. Ensuring permanence is essential to the environmental integrity of the entire cap-and-trade program. Because offsets allow for an equivalent quantity of GHG emissions within the capped sectors, the CO_2 stored in biological sinks resting from offset project activities must stay out of the atmosphere for a time period comparable to the emissions they are offsetting. If they do not, the net effect would be an increase in GHG emissions to the atmosphere. Scientific estimates of the atmospheric lifetime of anthropogenic CO_2 emissions are uncertain, as CO_2 is removed from the atmosphere by a number of processes that operate at different timescales. However, 100 years should really be viewed as a minimum time period for maintaining permanence because a fraction of anthropogenic CO_2 is expected to remain in the atmosphere well beyond 100 years as it is gradually removed through processes such as silicate weathering. The period of 100 years is frequently used in international climate change policy as a standard frame of reference for determining global warming potentials and setting GHG

emission reduction targets. Consequently, the use of 100 years to define the permanence of reductions is consistent with other programs.

Credit Calculations

N-3. Comment: While this version of the proposed ARB approach to measuring the global climate benefits of using wood waste for renewable energy continues to be in sync with other State, national, and international approaches (i.e. clear global benefits when produced as a by-product of sustainable forestry and a low-waste systems of using wood products rather than other energy-intensive products), this position appears to contradict one of the forest offset protocols authored by the non-governmental organization Climate Action Reserve (CAR). Continued reliance on the CAR formula will overestimate global climate benefits. By not considering the renewable energy generated by burning wood waste, the CAR formula effectively assumes all wood waste used for energy is a negative outcome from a global carbon cycle perspective. Unless the formulas used in CAR forest protocols are clarified and properly take into account emissions and benefits associated with wood products, there is the risk that overpriced and artificially inflated offsets will enter the system and later, need to be adjusted downwards.

Section 95852.2 clearly defines that the carbon dioxide emissions from energy produced from mill residues and post-consumer wood waste and wood and wood waste from regulated sustainable forestry operations, are "emissions without a compliance obligation." This approach is in sync with CEC, CPUC, U.S. EPA, and every country that signed the Kyoto Protocols. They all count wood residues used for energy as a climate benefit.

Further, in the Compliance Offset Protocol U.S. Forest Projects document (authored by a party that other than ARB (who is the responsible entity for representing the State of California), there are 13 references for details on how many pollution credits will be given to projects referring to 'the Forest Offset Protocol Resources section of ARB's website.' They all hotlink to http://www.climateactionreserve.org/how/protocols/adopted/forest/resources/.

It is clear that the ARB regulations put out for public comment are incorrect as this link is not to an ARB website but to a non-governmental site that has not been properly vetted through appropriate governmental channels and notification requirements. Upon close examination of the formulas, the site uses a very different approach than Article 5 with regard to accounting of climate benefits of wood wastes used for energy. This is important in California since we have no significant paper mills that use wood chips but do have a many wood-to-energy plants that generate renewable electricity. While there are many metrics used to measure wood (e.g. board feet, cubic feet, green tons, bone dry tons), the most recent survey of sawmills in California and other Pacific Coast states calculated that only one-half of the wood volume coming into the sawmill on log trucks leaves the sawmill as dimensional lumber (shown below in 'Table 3' from Keegan et al (2010)). National survey data of harvest sites and sawmills published in tables 39 and

42 in Forest Resources of the United States, 2007 (Smith 2009), also confirm that around one-half the initial total biomass from a harvested forest does not end up in dimensional lumber or products made from wood chips such as oriented strand board (OSB). A significant portion of the wood not going into dimensional lumber in California is used for energy.

Since only long lived wood products are considered as a climate benefit under the CAR formulas, all the wood waste used to generate renewable energy is essentially considered a negative outcome in the 'baseline harvest scenario' where wood waste is used for energy. The reduction of harvested wood used for energy is therefore credited as a climate benefit in the 'improved forest management (IFM) project' based on a 'with and without comparison.'

When measuring climate benefits under the 'with project' and 'without project' scenario, IFM projects form the basis for deciding how many pollution credits a project earns when sold through CAR. The CAR protocols continue to count all the carbon in wood residues used to generate energy as a 100 percent emission rather than as a true carbon benefit that can be measured by the avoided emissions from fossil fuel burning. This is a critical distinction between the CAR formulas and the proposed ARB regulations designed to govern the use of carbon credits in a reputable Cap and Trade program.

The CAR formula significantly inflates the apparent climate benefits of an IFM project since all the wood residues used for energy from the logging operation, the sawmill operation and post-consumer collection operations are considered as emissions rather than substitutions for fossil fuels. After the useful lifetime of wood products is over, much of the construction debris and wood is collected and burned to generate renewable energy in urban waste-to-energy plants. These benefits also appear to be ignored in the CAR accounting scheme. The net result of this accounting approach is that one ton of CAR-defined emission offset credits from an IFM project based on reduced levels of products should be discounted by the CO_2produced from the fossil fuels used to generate the renewable energy will not be generated from wood waste. If this distinction is not made and accounted for early in the verification process, there will be a net increase in global emissions for every IFM credit authorized. The fact that wood used for energy is not considered 'carbon neutral' by CAR could inflate the number of credits by 50 percent or more. This inflation factor will further flood and erode the "market" with over-valued credits, thus contributing to questions about the accounting controls over the carbon market economy.

The climate advantages of RPS-energy are well documented and are an integral part of State policy (California Energy Commission 2009) because they increase carbon sequestration of fossil fuels that can stay buried rather than be burned to generate energy for Californians. However, it appears that the accounting formulas buried deep inside the CAR forest offset protocols will end up allotting tradable carbon credits for projects that reduce historical and sustainable levels of renewable energy production. This may have been an unintended outcome of a fairly lengthy and complex protocol.

Since these regulations are authored by ARB rather than the non-governmental Climate Action Reserve, it would seem necessary for the calculations of the climate benefits related to wood waste used for energy to match those in “Article 5: California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms” rather than rely on information and formulas posted on a website outside of the control of ARB. This will require more than pasting and copying the CAR webpages to ARB web pages, since the overarching ARB regulations define wood use for energy as essentially carbon neutral. (UCB3)

> **Response:** It is appropriate for the forest protocol to treat wood residues as “waste.” Any benefits created by the combustion of these residues at capped sectors as replacement of fossil fuels is accounted for appropriately under the MRR and exemptions in the regulation.

N-4. Comment: The quantification calculation (section 6.2.6) is done annually and does not take into account timing of harvest and would require secondary effects contributions from projects that over time increase harvest above average baseline carbon harvests and thus have no reduced harvesting secondary effects. Since a project that increases onsite carbon additionality and increases offsite storage of carbon in wood products is sequestering the maximum carbon dioxide, such a result (project) should not be discouraged. This methodology also applies the 20 percent multiplier to total onsite carbon harvested when the leakage effect is only applicable to the harvested wood products, since all other pools are required to be stable or increasing, this over-estimates the leakage effect. The required on-site stock maintenance or increase takes care of the carbon in the non-product portions of harvested trees at issue. An identical over-estimate occurs in the contribution to landfills for those projects that harvest more than baseline. See Appendix C in Section C.4. This calculation requires landfill deductions even though the project increases wood product production as compared to baseline. We believe further discussion of C.4 and section 95976 is warranted. (CFA3)

> **Response:** We understand the commenter’s concern about the quantification of secondary effects (emissions leakage) due to decreased harvest; however, the forest offset protocol adopted by ARB addresses this concern already with a change that was initially incorporated into version 3.2 of the Climate Action Reserve forest project protocol and subsequently into ARB’s protocol. In section 6.2.6, when secondary effects due to harvest are evaluated, the differences between actual and baseline harvest for the current and all previous years are summed. If the result is that actual harvest has exceeded baseline harvest over the life of the project, then the discount is not applied in the current reporting year. However, if the baseline harvest has exceeded actual harvest, then the deduction is applied in the current reporting year. The equation that addresses carbon in harvested wood products entering landfills functions in the same manner, by evaluating the summed difference between actual and baseline

carbon entering landfills over the project life before determining if the deduction will be applied in the current reporting year.

The application of the secondary effects deduction for reduced harvest to total onsite carbon harvested (rather than only the carbon entering wood products) is appropriate because the full effects of emissions leakage involves all the carbon in the harvested trees, and not just the wood products. The deduction for the secondary effects is only applied once, and we do not agree that the onsite carbon stock maintenance requirements account for the non-product portion of the emissions leakage.

Easement

N-5. (multiple comments)
Comment: The protocol requires Avoided Conversion projects use a Qualified Conservation Easement (or transfer to public ownership). For most if not all owners of forest projects with historic easements and start dates, it will be impossible to petition easement holders to bear the administrative and legal costs of evaluating potential new liabilities established by the addition of Qualification language, and then re-drafting, executing and registering the modified easement. As a result, credits from Avoided Conversion projects registered under Early Offset programs or with historic start dates will be almost entirely excluded from the AB32 compliance market. We recommend that ARB modify the definition of Avoided Conversion projects to those "preventing the conversion of forestland to a non-forest land use by dedicating the land to continuous forest cover through a conservation easement or transfer to public ownership," matching the definitions and requirements for Avoided Conversion projects of the Climate Action Reserve's Forest Project (FPP 3.1 & 3.2, Section 2.1.3). (BLUESOURCE3)

Comment: The protocol requires that while an IFM project may have a Qualified Conservation Easement, it is not required. However, Qualified Conservation Easements are required for avoided conversion projects. We assume there will be no landowners who will adopt a Qualified Conservation Easement under ARB due to the requirements. This is a minor issue for IFM projects since they will still be eligible for ARB offsets (although they will suffer a discount due to increased buffer pool contributions). However, the requirement for a QCE for an avoided conversion project will be a significant obstacle since projects without one will be ineligible. While it may be possible to include a QCE in a new conservation easement, it will be nearly impossible to have any historical easement modified to include the language required by ARB to be considered a Qualified Conservation Easement. We request that ARB allow avoided conversion projects with easements prior to February 28, 2015 to be allowed to register with ARB without a QCE and that any project already registered or listed be allowed to continue without amending its current easement. (FINITE2)

Response: We did not make a change, as the protocol is explicit in the types of rights provided to ARB in the conservation easement. We made modifications to terminate ARB's interest in the easement if the forest project has met its carbon commitments or been terminated. We believe the requirement for ARB inclusion in the conservation easement is essential to our ability to ensure permanence in the offset project.

N-6. Comment: In regards to section 3.5, Use of Qualified Conservation Easements, we would like to reiterate this point from our comments submitted on August 11th: We understand the need for ARB to have the ability to intervene in conservation easement issues that relate to carbon offset projects. However, we think that ARB having the same enforcement authority as the easement holder, and broadly defined to encompass all aspects of an easement, is overly broad and could create confusion about roles and responsibilities. We think it is more appropriate to 1) narrow ARB's scope of concern to provisions of easements that affect the integrity of offset projects, and 2) to clearly define the time at which it is appropriate for ARB to intervene in the execution and enforcement of the easement. We believe that requiring holders of qualified conservation easements for carbon offset projects be accredited by the Land Trust Accreditation Commission should provide a layer of assurance that easements will be properly executed and ARB should only have the right to intervene when such land trusts have demonstrably failed to enforce provisions of qualified easements that adversely affect carbon projects. We would like to work with ARB to craft acceptable language. (PFT4)

Response: While the commenter provides some specific cases on how and when ARB's interests could be limited in a conservation easement, we did not make the change. These requirements are written broadly, as we cannot anticipate all situations under which we may need to exercise enforcement authority or intervene to ensure that the permanence requirements of the offset project remain intact. No other commission can substitute for the regulatory enforcement duties of ARB in implementing its programs.

Early Action

N-7. Comment: The proposed modifications include some positive changes to require offset projects to transition to more recent versions of the Forest Offset Protocol in the future, and even to recalculate the project baseline at the time of transition. For example, "[a]t the time of transition the early action offset project must calculate its project baseline based according to all the provisions in Compliance Offset Protocol U.S. Forest Projects . . . ." However, the regulation continues to allow the registration of early action credits generated under earlier versions of the protocol with no evaluation of the additionality of those credits. "ARB shall accept early action offset credits from early action offset projects registered with Early Action Offset Programs approved pursuant to section 95990(a), if the early action offset credits meet the criteria set forth in this section." In fact, the only substantive requirement for registration of early action forest offset credits is the contribution to the buffer account; that account, of course, is intended to mitigate the risk of reversal, not non-additionality. See section 95990(c)(5)(D) ("Climate Action Reserve Forest Project Protocol versions 2.1 and 3.0 through 3.2, if the early action offset project contributes early action offset credits into a buffer account based on its reversal risk calculated according to the Compliance Offset Protocol U.S. Forest Projects, [DATE]."). It therefore appears that offset credits from forest projects registered as early actions using version 2.1 of the Forest Offset Protocol can continue to be registered through 2015 even if the forest project does not choose to transition to the compliance program. "Early action offset projects must transition to ARB Compliance Offset Protocols no later than February 28, 2015." Therefore, non-additional credits can continue to be registered, and indeed can continue to be generated through 2015, using the non-additional baseline requirements of Forest Offset Protocol version 2.1. (CBD5)

> **Response:** At the time of initial crediting in the voluntary program, the early action projects had to meet the additionality requirements of the voluntary offset protocol and the early action program. Once an early action offset project transitions to ARB, it must meet the additionality requirements of the Compliance Offset Protocol and regulation. We believe the early action credits that would be eligible to be issued ARB offset credit for the early action protocols are additional.

N-8. Comment: The intent behind the requirement in the Forest Protocol for voluntary projects to meet "all legal and contractual requirements to allow it to terminate its project relationship with the voluntary offset program" is confusing and could pose unintended consequences. As written, it would require an Early Action project that does not plan to transition (as allowed under sections 95990(d)(1) and (h)(5)(A)) to terminate its contracts with the Climate Action Reserve and with all parties to whom they have sold their credits. This language as written could eliminate Early Action projects in California from participating in the cap-and-trade program and conflicts with the language in section 95990. PG&E recommends that this language be modified as follows:

> "If the offset project was an offset project in a voluntary offset program, <u>other than the Climate Action Reserve,</u> the offset project can demonstrate it has met all legal and ~~contractual~~ <u>protocol</u> requirements to allow it to terminate its project relationship with the voluntary offset program and be listed using this compliance offset protocol." (PGE5)

> **Response:** The requirements in the Compliance Offset Forest Protocol only apply to projects that transition over to the compliance program. They do not apply to Early Action Projects. The commenter has erroneously applied compliance project requirements to Early Action Project requirements, which is not the intent.

Forest: General

N-9. Comment: Per section 6.2.1.1 (page 50 of the Compliance Offset Protocol for U.S. Forest Projects, Sept. 2011), a 'logical management unit' or 'LMU' must where even aged management is utilized, have a uniform distribution (by area) of 10-year age classes that extend to the normal rotation age (variation of any 10-year age class not to exceed 20 percent. This is an impossible test as most areas have histories which prevent this uniform distribution by age class and if there is any necessary test on age class distribution it is already included in the project requirements for Natural Forest Management under Section 3.8.2 and shown in Table 3.2. (CFA3)

> **Response:** We understand the concern that the definition of a Logical Management Unit (LMU) may not be readily applicable to all management situations. However, the forest protocol recognizes this possibility, and offers an alternative approach that is similarly conservative in evaluating whether carbon stocks within the project area are significantly different from the forest owner's broader management practices in the area. In situations where an LMU containing the project area cannot be identified, the protocol requires that an LMU instead be defined by all lands where the forest owner or its affiliate(s) either own in fee or hold timber rights within the same assessment area covered by the project boundary. This alternative definition should be readily applicable in the situation described by the commenter.

N-10. Comment: While very few pools would be affected by site prep, for early action projects this pre-site prep inventory cannot be measured (section 6.1.1). We suggest adding a professional estimate by an RPF based upon non-reforested areas nearby and including a specific requirement for the verifier to check this estimate for reasonableness. (CFA3)

> **Response:** The ARB Forest Offset Protocol requirement that carbon pools affected by site preparation activities must be conducted prior to any site preparation activities is contained in versions 3.0 through 3.2 of the CAR protocol, though the requirements are more detailed in version 3.2 and the ARB protocol. We are not aware of any early action reforestation projects under version 2.1 of the CAR protocol. Consequently, we do not see any barriers to transition for early action reforestation projects that followed the requirements in versions 3.0 through 3.2 of the CAR Forest Project Protocol and conducted inventories of carbon stocks prior to site preparation activities.

N-11. Comment: In section C.4, we believe the verifier could evaluate the project and determine if the project will actually harvest more than the baseline over the crediting period and correctly calculate these contributions. This decision can be reevaluated at each six year site visit and if needed be corrected in the inventory true-up process. (CFA3)

> **Response:** This comment falls outside the scope of the second 15-day changes to the regulation. Therefore, no response is required.

N-12. Comment: The default financial risk in section D.1 continues at 5 percent of all offset credits issued, which is far too high. There is no evidence of a 5 percent rate of financial failure for forest owners. The CAR Workgroup believed a 1 percent default financial risk for most projects and less than 2 percent for small non-capitalized projects was sufficient. We recommend ARB change the 5 percent to 2 percent and allow the verifier to consider forest owner capitalization and allow reduction to 1 percent. (CFA3)

> **Response:** This comment falls outside the scope of the second 15-day changes to the regulation. Therefore, no response is required.

N-13. Comment: We continue to believe the setting of a default for other Episodic Catastrophic Events is an error. The category is for places predominately outside of California. The verifier should provide the most appropriate value, if any. (CFA3)

> **Response:** The risk rating for episodic catastrophic events may cover a variety of risks not accounted for in other categories. At the outset of the cap-and-trade program, there are not sufficient data to determine if all the initial risk values used in determining the forest buffer account contribution have been calculated appropriately. However, in the absence of better risk data, we believe that it is important to err on the side of having the risk factors too high to ensure that there is a sufficient quantity of offset credits in the forest buffer account to cover any reversals in the early years. These risk ratings may be decreased or adjusted at a later time once more data are available on the rate of reversals due to various risks and the functioning of the forest buffer account. It is conceivable that these average risk ratings could be adjusted based on geography, eco-region, and other factors in the future, but it is not possible to conduct such an analysis at this time.

N-14. Comment: The provisions in sections 2.1.1, 2.1.2, and 2.1.3 of the forestry protocol are confusing and could inadvertently create problems for a wide swath of early action credits. It appears to require 100 percent of credits in a particular registry to transition, eliminating the possibly of selective transitioning according to need. CERP urges ARB remove such provisions from section 2.1.1, 2.1.2, and 2.1.3 of the Forestry protocol at this time, and add a process for credits from additional registries to be included in the compliance protocol as part of the next rulemaking, which is to take place next year. If ARB wishes to retain such language in the forestry protocol, it should at least modify the phrase “legal and contractual relationships” to state instead “legal and contractual obligations related to the offset credits in question” or make clear that such provisions do not apply to early action projects. (CERP5)

> **Response:** Those provisions only apply to projects that transfer over the compliance program. There is nothing in the protocols themselves about early action credits; therefore, those provisions do not apply to early action credits.

N-15. Comment: As we have stated in previous comment letters, the Compliance Offset Protocol U.S. Forest Projects (“Forest Offset Protocol”) contains provisions that fail to ensure compliance with the controlling additionality requirements of AB 32. Health and Safety Code section 38562(d)(2). The Forest Offset Protocol also is unlikely to ensure compliance with ARB’s proposed regulatory additionality requirements under Section 95973(a)(2)(A). In particular, as addressed in our previous comment letters, the

Forest Offset Protocol allows projects to include in the project baseline forest growth projected to occur under the business-as-usual scenario described by longterm management plans required for timber operations under the California Forest Practice Rules. Those flaws persist in the version of the Forest Offset Protocol currently before the Board; as a result, the protocol continues to fail the additionality test of AB 32. Additionality problems are even more serious in earlier versions of the Forest Offset Protocol, in which the business-as-usual baseline is allowed to reflect the regulatory minimum (i.e. maximum potential harvest levels), regardless of whether the project developer ever could or would have operated at that baseline. As a result, version 2.1 of the Forest Offset Protocol used in early action measures includes a definition of project baseline that facilitates and invites nonadditional credits to an even greater degree than the Forest Offset Protocol adopted by ARB as part of the cap-and-trade regulation. Yet ARB, in the current regulation, still proposes to allow credits generated under these prior versions of the protocol to be brought into the Cap-and-Trade compliance market as “early action” mechanisms. The result of this proposal will be the creation of a large number of demonstrably non-additional credits that will undermine the integrity of the compliance scheme as a whole and inhibit achievement of AB 32’s emissions reduction goals. (CBD5)

> **Response:** We agree with the importance of ensuring that all credited greenhouse gas emission reductions and removal enhancements from forest projects are additional. The performance standard tests in the protocol are designed to provide reasonable assurance that credited greenhouse gas reductions or removal enhancements meet the regulatory definition of additionality, which requires that greenhouse gas emission reductions or removals exceed any greenhouse gas reduction or removals otherwise required by law, regulation or legally binding mandate, and that they exceed any greenhouse gas reductions or removals that would otherwise occur in a conservative business-as-usual scenario.
>
> At the time of initial crediting in the voluntary program, the early action projects had to meet the additionality requirements of the voluntary offset protocol and the early action program. Once an early action offset project transitions to ARB, it must meet the additionality requirements of the Compliance Offset Protocol and regulation. We believe the early action credits that would be eligible to be issued ARB offset credit for the early action protocols are additional.

N-16. Comment: Section 95983 (page A-269) is intended to address the risk of reversal of forest projects. “The amount of ARB offset credits that must be placed in the Forest Buffer Account shall be determined as set forth in Compliance Offset Protocol U.S. Forest Projects.” That is, the contribution to the Forest Buffer Account is based on Appendix D, “Determination of a Forest Project’s Reversal Risk Rating,” at page 108 of the Forest Offset Protocol. However, the Forest Offset Protocol provides no calculations or rationale for the values attributed to the various reversal risks. For example, the risk of default due to overharvesting is set at 2 percent, with no explanation or citation. At best, the risk estimates appear to be based on general averages with no refinement for particular forest or project types. This also appears to be the case for the default risk due to forest fire. In this case, the general fire risk for a forest project is set at 4 percent, with risk reductions of 50 percent for projects with a “high level of fuel treatments,” approximately 33 percent risk reductions for projects with a “moderate level of fuel treatments,” and approximately 17 percent risk reductions for projects with a “low level of fuel treatments.” No explanation for these values and no definition of high, medium, and low fuel treatments are provided. Ultimately, this provision does not identify the risk of reversal specific to any forest project, and thus fails to address the liability that reversal of forest projects brings to the offset program as a whole. (CBD5)

> **Response:** We disagree that the calculations fail to address reversals. At the outset of the cap-and-trade program, there are not sufficient data to determine if all the initial risk values used in determining the forest buffer account contribution have been calculated appropriately. However, in the absence of better risk data and based on the principle of conservative accounting, we believe that it is important to err on the side of having the risk factors too high, to ensure that there is a sufficient quantity of offset credits in the forest buffer account to cover any reversals in the early years. These risk ratings may be decreased or adjusted at a later time, once more data is available on the actual rate of reversals due to various risks and the functioning of the forest buffer account.

N-17. Comment: The language in the second paragraph of section 2.2 stating that ultimately all forest owners are responsible for all project commitments creates confusion of responsibility. This language was removed from the definition section of the regulations (see above) but has not been fixed here. We recommend that the sentence be struck, and that one forest owner be allowed to be designated as having full responsibility for all project commitments. (PFT4)

> **Response:** While the forest owner designated as the Offset Project Operator will have the primary responsibility for managing the forest project in conformance with the protocol and the regulation, all forest owner(s) are ultimately responsible for all commitments associated with a forest offset project. In the instances where there are multiple forest owners, parties can use third-party contracts to establish an offset project developer and structure the liability for the involved forest owners.

N-18. Comment: The performance test for avoided conversion projects in section 3.1.2.3 includes a requirement that the slope of project areas where residential, commercial, or agricultural development is the anticipated converted land use cannot exceed 40 percent. It has come to our attention that there are areas in the Appalachian Mountains where residential development is legally permissible and regularly occurs in a manner that removes trees in areas that exceed 40 percent slope. Thus, the current language limits the ability of forest owners to use avoided conversion projects to prevent emissions from documentable business as usual situations. We recommend that this slope percent limitation be removed and replaced with the requirement to show that projects are eligible in areas where development is legally permissible and has been shown to occur in similar situations regardless of slope. (PFT4)

> **Response:** We acknowledge the comment, but any changes to the criteria that establish additionality through this performance test fall outside the scope of the second 15-day changes to the regulation. We will conduct periodic reviews and updates to this protocol, as appropriate, and we encourage the commenter to engage with us during a future update process for ARB consideration of this change.

Livestock Protocol

N-19. (multiple comments)
Comment: The livestock protocol could use the most up to date data available. The default values listed in the protocol are not consistent with the latest default values from the U.S. EPA's Inventory of Greenhouse Gas Emissions and Sinks. The protocol could be updated to reflect the latest data and clarify that project developers may use the latest publicly available EPA data even if it has not yet been added to an updated version of the protocol in order to anticipate future updates. (TCT2)

Comment: The defaults prescribed in the ARB Livestock Protocol for Volatile Solids and Livestock weight are out of date and are not consistent with the latest EPA reports. ARB should allow the use of the most recent versions of data, provided they are sourced from a recognized publication, in order to most accurately reflect emission reductions. (CIG3)

Comment: The weight of a lactating dairy cow has also changed from 604kg to 680kg (see as above but Table A-184, page A-222). ARB should clarify that Offset Project Operators are allowed to use the latest versions of the EPA-specified values. Not doing so may result in developers continually petitioning ARB and registries for variations to Protocols and/or verifiers continually seeking guidance from ARB. (CIG3)

> **Response:** The APA process requires our regulations to be very prescriptive. Any deviation from the protocols would be considered a noncompliance. We will update protocols with new data and emissions factors as part of periodic reviews and updates.

N-20. Comment: We applaud ARB in selecting offsets generated by using CAR Livestock Protocol as eligible to be used as early action offsets under the cap-and-trade program and for providing continuity to project developers by incorporating many of the aspects of the current CAR Livestock Protocols. (CIG3)

> **Response:** Thank you for your support.

ODS Protocol

N-21. Comment: The Ozone Depleting Substances (ODS) Protocol ignores the fact that new, more efficient technologies have been developed and deployed to capture and destroy ODS from refrigerators and their foam insulation. These technologies have become more cost-effective, and demand has grown to avoid ODS releases to the atmosphere. As a result, the traditional approaches of draining ODS from refrigerator compressors, storing non-economic captured ODS indefinitely, and landfilling the ODS laden foam have gradually become more unacceptable and non-competitive. This evidence establishes that the proposed business-as-usual baseline in the proposed ODS protocol is inaccurate and the ODS protocol would provide offsets for many non-additional projects that are already underway. These projects do not meet the AB 32 criteria for additionality. U.S. Department of Energy funding and other programs have played a role, as has the development of ODS capture and destruction technology in Europe. As a result, much of the ODS destruction that would receive offset credits under the protocol would not be additional to what would have occurred in the absence of the AB 32 program. (WILLIAMSZ3)

> **Response:** The documentation in the CAR ODS protocol provides the data and calculations supporting the <1.5 percent of recoverable U.S.-sourced ODS that are destroyed upon end-of-life. The original data source is ICF International (2009), *Destruction of ODS in the United States and Abroad*, prepared for the U.S. Environmental Protection Agency. Some ODS are destroyed today, but the data shows it is far from common practice. We believe the regulatory verification process and ARB's oversight of the offset program will provide for a rigorous offset issuance process. In the unlikely event that any fraud is found after issuance, ARB retains the authority to invalidate a fraudulent offset and require it to be replaced to maintain the environmental integrity of the program.

N-22. Comment: We disagree with the values ascribed to the GHG emissions of CFC-13 substitutes in the Protocol that would significantly impact the amount of GHG emissions associated with a potential CFC-13 project. The proposed values are inaccurate and would make any CFC-13 project economically non-viable. When CFC production ended, R-508 became the industry standard replacement for CFC-13. With growing concern over the global warming potentials of refrigerants, producers of ultralow temperature freezers have been phasing out use of R-508. This has already happened in Europe, and is now underway in the United States. As is the case across many sectors, there are additional, viable "third-generation" alternatives for CFC-13 that are in use which have not been submitted for SNAP review nor proposed by U.S. EPA for addition to the list of SNAP acceptable substitutes. For all of the CFC refrigerants, the CAR and ARB ODS Protocols include an estimated emission factor associated with the substitute refrigerants based on market penetration of various substitutes and the average charge size and leak rates. In the September draft protocol, the emission factor for CFC-13 substitutes is 7,144 lbC2OE / lbODS destroyed. To generate an updated emission factor for CFC-13 substitutes, EOS conducted market research via consultations with the manufacturers of ultra-low temperature freezers and reclaimers on the market penetration of CFC-13 alternatives. Our analysis found that typical R-13 charges in ultra-low temperature freezers are between 0.5 and 1.0 lbs. In other refrigerant applications, the charge size of hydrocarbons, HFCs and other CFC substitutes typically are half the charge size as the original ODS. Using this, we assume an average charge size of 0.5 lbs for CFC-13 substitutes. Based on the leak rates for commercial and industrial refrigeration equipment in the IPCC/TEAP report and the CAR working group survey, we conservatively assume a 15 percent leak rate. Based on the current market analysis, and the assumptions made above on replacement charge size and leak rate, the CFC-13 substitute emission factor is calculated as 1,141 lbC2OE /lbODS destroyed. This is approximately 16 percent of the substitute emission factor given in the September 2011 Protocol. (EOSC4)

> **Response:** We chose conservative values for the substitute and the related global warming potential (GWP). There is conflicting information on the market share of substitutes. Information from manufacturers and government entities indicted that the most common substitutes were R-23 (with a GWP of 11,700 according to the Second Assessment Report) or R-508 (with a slightly lower GWP). We chose the larger GWP value to be conservative, since no reliable market share information was available. This GWP combined with a 1-to-1 replacement charge size, and the leakage rate defined by California's Refrigerant Management Regulation provides the substitute factor used in the protocol.

N-23. Comment: ARB has proposed an average annual emission rate of 9 percent for CFC-13. We assume this is derived from a single data point in the database that ARB has compiled from SCAQMD Rule 1415 reporting. In that database, one facility reported an annual leak rate of 9.4 percent for CFC-13 equipment. We believe this is overly conservative, based on insufficient data. A survey conducted by the Climate Action Reserve ODS working group reported a range of annual leak rates for CFC-13 between 7 and 33 percent. The 2005 IPCC/TEAP Special Report on Safeguarding the Ozone Layer and Global Climate System listed an average leak rate for commercial refrigeration and industrial process refrigeration of 17 percent and 18 percent respectively. CFC-13 has been used in low temperature commercial and industrial applications, including ultra-low temperature laboratory freezers as well as larger units. Based on our work with refrigerant reclaimers and facility owners and operators, demand for CFC-13 remains in high demand to recharge high value older equipment. According to the companies who are servicing the equipment, these older units commonly leak because of their age and high-pressure requirements; in many cases 100 percent of the refrigerant charge is released. We believe a more accurate, and conservative leak rate for CFC-13 is 17 percent. (EOSC4)

> **Response:** The leakage rate value of 9 percent is based on compliance with California's Refrigerant Management Regulation, which requires leak detection and repair. The mix of CFC-13 uses covered by the regulation and those not covered is unknown; therefore, we chose to be conservative and apply the lower leakage rate of 9 percent to all CFC-13 uses.

Miscellaneous

Comment: Forestry offsets are notoriously unverifiable, and inherently provide no reduction in toxic and smog-forming co-pollutants. (CBE3)

> **Response:** We disagree that offsets are unverifiable. We believe the accounting, monitoring, and verification standards in the program will provide assurance that only real sequestered carbon is issued ARB offset credits. The role of offsets is to provide GHG reductions or sequestration, not to specifically address toxic or smog-forming co-pollutants.

Comment: The Urban Forestry Protocol appears to encourage planting non-native species, which can cause environmental harms, by introducing invasive species or species with high water needs, among others. For example, since the protocol bases offset credits on tree size and speed of growth without prohibiting non-natives, it could encourage planting inappropriate, invasive species such as eucalyptus in California, or other inappropriate species outside California. Moreover, while urban tree planting in general is a good thing, it cannot be considered remotely equivalent to reducing emissions from an oil refinery, and so does not offset that pollution. (CBE3)

> **Response:** The protocol contains a list of specific urban tree types that are eligible under the protocol. Each project developer will decide which types of trees to include in their project. These choices will be made based on several factors, such as climate, aesthetics, and maintenance. The aim of the protocol is to sequester carbon to offset GHG emissions from covered sources. In that aspect, planting a tree for carbon sequestration purposes is appropriate for addressing GHG emissions from a refinery.

Comment: ODC offsets assume that the State will not adopt any additional controls of ODCs, which is an obvious alternative. California could set standards requiring that instead of being used as offsets, ODCs in foam and refrigerators be destroyed, rather than recycled. (CBE3)

> **Response:** We discuss the philosophy of direct regulation and market based regulations in several spots of the FSOR. However, each protocol has a limited crediting period. This allows a review for regulatory additionality before any new projects can be issued credits. The adoption of an offset protocol does not prevent ARB from considered a direct regulation for those sources at a future date.

O. OPPOSITION AND SUPPORT

Opposition

O-1. Comment: Cap and trade is a horrible idea. Don't destroy California's economy. (FORMLETTER13)

> **Response:** This comment falls outside the scope of the second 15-day changes to the regulation, and no response is needed. However, as we explained in the 45-day changes to the regulation, we conducted a thorough evaluation of both the health and economic effects of the proposed program to ensure to the extent feasible that no disproportionate negative impact will occur. We have designed the cap-and-trade program to minimize the cost of implementation and compliance and to maximize the overall benefits.

Support

O-2. (multiple comments)
Comment: CERP believes that ARB has taken a number of positive steps in the latest round of revisions to its cap-and-trade regulations. Such changes will improve the workability of the program while maintaining a high level of environmental integrity. CERP commends ARB staff for its tireless work to implement the first in the nation cap-and-trade program while under significant time and staff constraints, and for its careful consideration of comments provided in response to earlier versions of the regulations. (CERP5)

Comment: WSPA reiterates its support for a market-based approach to industrial emissions in the implementation of AB 32. We continue to believe that a well-designed market based approach will be the most effective means to meet the Greenhouse Gas (GHG) reductions mandated by AB 32. (WSPA4)

> **Response**: We appreciate the support.

P. USE OF AUCTION PROCEEDS

P-1. Comment: Raising funds via an auction for reasons outside of administrative fee purposes is beyond CARB's regulatory authority. (CALCHAMBER4)

> **Response:** This comment falls outside the scope of the second 15-day changes to the regulation.

P-2. (multiple comments)
Comment: We disagree with ARB's decision to remove the provisions in the rule providing guidance to the electric IOUs on how to return auction revenue for the benefit of their retail customers. The provisions simply ensure that the IOUs' use of allowance value will not mute the carbon price signal embedded in retail rates or be tied exclusively to a utility customers' energy consumption. Maintaining the carbon price at the retail level is at the heart of ARB's allocation scheme for the utility sector and reflects the consensus recommendation of nearly every expert body that has examined the issue. Moreover, as designed, it is our view that the provisions would not unduly interfere with the California Public Utilities Commission's (CPUC) jurisdiction over rate setting. Although ARB's rationale to remove the provisions rests on questions of legal authority, we are concerned that stakeholders will attempt to construe ARB's decision as signaling a change of position from a policy perspective. Past CPUC decisions have called for ARB's judgment on this issue, and ARB's position will be significant in shaping the ultimate resolution for allocating allowance value from the electricity sector. Should ARB proceed with the proposed changes, we therefore ask that ARB reaffirm unequivocally its expert conclusion that "staff believes that any rebates to residential customers should be made as separate payments and not simply deducted from customer bills. The purpose of this restriction is to ensure the carbon price is reflected in residential electric rates" (emphasis added). (KUSTIN19)

Comment: We disagree with ARB's decision to remove the provisions in the rule providing guidance to the electric IOUs on how to return auction revenue for the benefit of their retail customers, Section 95892(d)(3) page 143 of the revised draft. We do not believe that the provisions would unduly interfere with the California Public Utilities Commission's (CPUC) jurisdiction over rate setting. (CPC7)

> **Response:** As the commenter notes, we removed the provisions regarding use of auction proceeds for allowances consigned by utilities based on ARB's lack of authority to appropriate funds. We acknowledge that electrical distribution utility proceeds from the sale of allowances at auction would most likely fall under limitations imposed by either the California Public Utilities Commission or by the governing bodies of publicly owned utilities, and that these entities have exclusive electricity ratemaking authority.
>
> Proper carbon pricing is the primary way in which the cap-and-trade program achieves emissions reductions. Compensation provided volumetrically (per megawatt-hour consumed) will not create the correct incentives for greenhouse

gas reduction. Volumetric return of allowance value eliminates incentives for greenhouse gas reduction strategies such as conservation of electricity, efficient combined heat and power, and distributed electrical generation.

When we determined that allowance value should be allocated to electrical distribution utilities on behalf of customers, we made this decision with the explicit understanding that value would not be used to skew carbon pricing or reduce incentives for greenhouse gas reductions. We retain the authority to revoke free allocation if it is used in a way that is counter to the statutory objectives of AB 32.

Our Economic and Allocation Advisory Committee (EAAC) recommended against allocating allowance value to electrical distribution utilities because the EAAC believed that preventing increases in electricity rates would be the likely outcome of this allocation approach.

Carbon price signals in electricity rates should reflect the emissions rate of the marginal generator dispatched into the power markets. In establishing the appropriate carbon price in rates, the CPUC and POU governing boards will need to account for the costs of other greenhouse gas-reducing policies, including the 33 percent renewable portfolio standard and the impact of these programs on electric rates.

We continue to believe that rebates to residential customers should be made as separate payments, and not simply deducted from consumer bills.

In Resolution 11-32, the Board directed the Executive Officer to work with the California Public Utilities Commission (CPUC) and publicly owned utilities to reflect the findings of the Board that the impact of the cap-and-trade regulation on electricity rates creates appropriate incentives to further the goals of AB 32. The Board also directed the Executive Officer to work with the CPUC and the publicly owned utilities to reflect the finding of the Board that if allowance value provided to the electric distribution utilities for ratepayer benefit is returned directly to customers, it is consistent with State efforts to promote energy efficiency and energy conservation.

P-3. Comment: CARB proposes to allocate allowances to EDUs based on the electricity consumption through their respective service franchises and then require these allowances to be auctioned with the proceeds being used for the benefit of the EDUs' ratepayers. Since no allocations will be made to the "industrial cogeneration/distribution" entities delivering electricity directly to their rate-paying customers, there is an unequal (one-sided) opportunity to offer benefits to the ratepayer which favors the EDU. This will provide an incentive for current (and future) consumers of industrial cogenerated power to switch to grid-delivered power—a result contrary to CARB's policy objective of incentivizing cogeneration power. To prevent this unequal treatment, CARB must either allocate allowances to industrial cogeneration/distribution entities in a manner consistent with the proposed allocation to EDUs under section 95892, or revise the proposed regulations to explicitly require that cogeneration power customers receive the same benefits under section 95892(d)(3) as other EDU retail ratepayers. CARB staff has stated that the intent of the allocations to EDUs is to mitigate the anticipated added “cost of carbon” imposed upon all electricity consumers, regardless of where the electricity consumer sources their power supply. In CARB’s words, EDUs would be required to share the benefit of their monetized allowance allocations with all consumers connected to the EDU’s system, even if the power consumer is not purchasing power through the EDU. That intent notwithstanding, there is conflicting language in the proposed rules that would appear, at a minimum, to not require, and at worst, to preclude the distribution of EDU allowance value to those electricity consumers supplied directly by an industrial CHP facility. Air Products requests CARB add clear language to the rule to explicitly require sharing of allowance value with CHP customers. Modify section 95892(d) as follows:

> (4) ~~Investor owned~~ <u>Electrical distribution</u> utilities shall ensure equal treatment of their own customers and customers of <u>cogeneration facilities</u>, electricity service providers and community choice aggregators <u>such that the distribution of auction proceeds does not create an incentive for customers to change electricity suppliers</u>.

Alternately, CARB could clarify intent by adding a definition of “electricity service provider” to explicitly include industrial cogeneration facilities supplying power directly to a ratepayer. Currently, there is no definition of “electricity service provider” under the cap and trade rule, relying instead on definitions within California Public Utility Commission (CPUC). Within the CPUC Code, there are confusing and potentially conflicting definitions which appear to exclude cogeneration facilities, highlighting the need for clarifying language to be added directly to the cap and trade rule. To eliminate the confusion associated with a CHP being designated an electric service provider under CPUC rules, Air Products recommends CARB add the necessary definitions directly into the cap and trade rule to clarify that all CHP electricity customers are eligible for the distribution of auction proceeds. (APC3)

> **Response:** We did not adopt the language suggested by the commenter. However, we agree that allowance value given to electricity distribution utilities on behalf of their customers should not be used to eliminate incentives for greenhouse gas-reduction strategies such as conservation of electricity, efficient combined heat and power, and distributed electrical generation.

P-4. Comment: SCE commends ARB for removing the fixed rebate language, as the change will help ensure a successful cap-and-trade program. SCE commends ARB for removing Sections 95892(d)(3)(B) and (C), which required the electrical distribution utilities to return any allowance values to customers through the use of a fixed rebate or credit, rather than based on the quantity of electricity delivered to ratepayers. Removing this language will ensure that the decision of how to allocate allowance value to customers will be appropriately addressed by the CPUC—the agency with plenary jurisdiction to do so.

Additionally, from a policy standpoint, the removal of this language is a step in the right direction towards ensuring a successful cap-and-trade program. A fixed rebate would otherwise result in sudden rate increases for some customers, while potentially creating an incentive for others to increase their electricity usage. This approach would not garner the needed public support for the cap-and-trade program. SCE has and will continue to argue at the CPUC that an allowance value return that is proportionate to the emissions reduction costs incurred by customers will prevent all California electricity customers from experiencing sudden rate increases. Given the importance of this issue to the success of the cap-and-trade program, SCE thanks ARB for ensuring that it is addressed in the appropriate proceeding and in the appropriate jurisdiction. (SCE4)

> **Response:** We agree that the CPUC has the sole ratemaking authority for investor-owned utilities. However, we note that if allowance value is used in a way that is counter to the achievement of AB 32's goals, we retain the authority to revoke freely allocated allowances awarded to utilities. We will continue to work with CPUC to ensure that use of value appropriately incentivizes reduced emissions through efficient generation of electricity and demand-side reductions in electricity use.
>
> We still believe that a fixed rebate for residential customers would assist in achieving the greenhouse gas reductions required by AB 32. We do not agree with the commenter that return of value proportionate to electricity use is the correct incentive to reduce emissions.
>
> In Resolution 11-32, the Board directed the Executive Officer to work with the CPUC and publicly owned utilities to reflect the findings of the Board that the impact of the cap-and-trade regulation on electricity rates creates appropriate incentives to further the goals of AB 32. The Board also directed the Executive Officer to work with the CPUC and the publicly owned utilities to reflect the finding of the Board that if allowance value provided to the electric distribution utilities for ratepayer benefit is returned directly to customers, it is consistent with State efforts to promote energy efficiency and energy conservation.

P-5. Comment: The use of electricity is a significant cost to industry in California. If CARB ignores the additional costs that will be imposed on both the refining and oil and gas sectors by increases in electricity costs due to the pass-through of carbon costs, these sectors will be competitively disadvantaged, resulting in carbon leakage. We are also concerned that grid purchases are completely covered and are not diluted by the CPUC rulemaking. We understand that ARB staff has agreed that direct allocations will be provided to industry after the CPUC acts on utility pass-through rules and before the start of the first compliance year, and strongly encourage that agency action. (CHEVRON4)

> **Response:** We recognize the importance of indirect carbon costs. We will continue to work with the CPUC to ensure that a level playing field is created between grid purchases and distributed generation. We will consider potential

direct allocations to industry as an expansion of the existing benchmarks in a future rulemaking if necessary to minimize leakage. The allowances for any additional direct allocations would need to come, at least in part, from the portion of allowances currently allocated to electrical distribution utilities on behalf of their industrial customers.

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ATTACHMENT A: FINAL STATEMENT OF REASONS—Response to Comments on the Functional Equivalent Document Prepared for the California Cap on GHG Emissions and Market-Based Compliance Mechanisms

October 28, 2011

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Response to Comments on the Functional Equivalent Document Prepared for the California Cap on GHG Emissions and Market-Based Compliance Mechanisms

Table of Contents

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INTRODUCTION

To meet the requirements of the California Environmental Quality Act (CEQA) under ARB's Certified Regulatory Program, the California Air Resources Board (ARB) staff prepared and circulated for public review a Functional Equivalent Document (FED or environmental analysis) for the California Cap on GHG Emissions and Market-Based Compliance Mechanisms Regulation (Cap-and-Trade Regulation or Regulation). The FED was included as Appendix O to the Initial Statement of Reasons (Staff Report) prepared for the Regulation, and was circulated for public review and comment from October 28, 2010 to December 16, 2010. Two Notices of Public Availability of Modified Text and Availability of Additional Documents (15-Day Changes) were subsequently issued. The two sets of 15-Day Changes modified regulatory text to provide clarity and were largely administrative. Some of the regulatory modifications would result in the Regulation being more environmentally protective (offset provision and forest protocol). The modifications do not cause new or additional compliance responses by covered entities and do not affect the environmental impact analysis in the FED. Therefore, no revision to the FED analysis or recirculation of the FED is required. The ISOR entitled *Initial Statement of Reasons: Proposed Regulation to Implement the California Cap-and-Trade Program* and other rulemaking documents are available at ARB's rulemaking webpage at http://www.arb.ca.gov/regact/2010/capandtrade10/capandtrade10.htm.

This document presents ARB's written responses to comments on the FED that raise significant environmental issues and were received during the initial 45-day comment period, at the December 16, 2010 Board hearing, and during the comment periods for the two 15-Day Change Notices. In accordance with ARB's Certified Regulatory Program, the Board will consider the Response to FED Comments for approval prior to taking final action on the proposed Regulation.

Staff will also prepare written responses to *all* public comments received, not just FED comments, for purposes of the Administrative Procedure Act. The complete written responses to all comments will be included in the Final Statement of Reasons (FSOR) prepared for the rulemaking. Upon its completion, the FSOR will be made available in electronic form on the ARB rulemaking webpage at http://www.arb.ca.gov/regact/2010/capandtrade10/capandtrade10.htm.

Requirements for Responses to Comments

Responses to public comments are prepared in compliance with ARB's certified regulatory program, which states:

> *Public Resources Code (PRC) section 60007. Response to Environmental Assessment*
>
> *(a) If comments are received during the evaluation process which raise significant environmental issues associated with the proposed action, the staff shall summarize and respond to the comments either orally or in a supplemental written report. Prior to taking final action on any proposal for*

which significant environmental issues have been raised, the decision maker shall approve a written response to each such issue.

In CEQA, PRC section 21091 also provides direction regarding the consideration and response to public comments. While the provisions refer to environmental impact reports, proposed negative declarations, and mitigated negative declarations, rather than a FED, this section of CEQA contains useful information for preparation of a thorough and meaningful response to comments. PRC section 21091(d) states:

(1) The lead agency shall consider comments it receives … if those comments are received within the public review period.

(2) (A) With respect to the consideration of comments received …, the lead agency shall evaluate comments on environmental issues that are received from persons who have reviewed the draft and shall prepare a written response pursuant to subparagraph (B). The lead agency may also respond to comments that are received after the close of the public review period.

(B) The written response shall describe the disposition of each significant environmental issue that is raised by commenters. The responses shall be prepared consistent with section 15088 of Title 14 of the California Code of Regulations, as those regulations existed on June 1, 1993.

Title 14 CCR section 15088 of the State CEQA Guidelines contains useful information and guidance for preparation of a thorough and meaningful response to comments. It states, in relevant part, that specific comments and suggestions about the environmental analysis that are at variance from the lead agency's position must be addressed in detail with reasons why specific comments and suggestions were not accepted. Responses must reflect a good faith, reasoned analysis of the comments. Title 14 CCR section 15088 (a – c) states:

(a) The lead agency shall evaluate comments on environmental issues received from persons who reviewed the draft EIR and shall prepare a written response. The Lead Agency shall respond to comments received during the noticed comment period and any extensions and may respond to late comments.

(b) The lead agency shall provide a written proposed response to a public agency on comments made by that public agency at least 10 days prior to certifying an environmental impact report.

(c) The written response shall describe the disposition of significant environmental issues raised (e.g., revisions to the proposed project to mitigate anticipated impacts or objections). In particular, the major environmental issues raised when the Lead Agency's position is at variance with recommendations and objections raised in the comments must be addressed in detail giving reasons why specific comments and suggestions were not accepted. There must be good faith, reasoned analysis in

response. Conclusory statements unsupported by factual information will not suffice.

Comments Requiring Substantive Responses

Substantive responses are limited to comments that "raise significant environmental issues associated with the proposed action," as required by PRC section 60007(a). Therefore, responses specific to comments made on the Cap-and-Trade Regulation's environmental analysis are provided, consistent with the provisions of PRC section 60007. As explained above, other substantive comments are responded to in writing in the FSOR. Where a comment raises both an issue related to and issues not related to the FED, the FED-related comments are responded to in this document and the reader is referred to the non-FED responses in the FSOR.

Commenters

ARB received 19 comment letters that included comments on the FED, including comments from three public agencies. The list below identifies the commenters that submitted FED-related comments, and includes commenter information. The commenters are depicted identically to "Section III. A. List of Commenters" in the FSOR and the comment number corresponds with the comment number in the FSOR.

Commenter ID	Commenter Information
BLUESOURCE	Roger Williams Affiliation: Blue Source Written Testimony: 12/13/2010 45-Day Comment #: 660
CBD1	Brian Nowicki and Kevin Bundy Affiliation: Center for Biological Diversity Written Testimony: 12/15/2010 45-Day Comment # 746
CBD4	Nick Lapis, Californians Against Waste; Paul Mason, Pacific Forest Trust; Peter Miller, Natural Resources Defense Council; Brian Nowicki, Center for Biological Diversity; Timothy O'Connor, Environmental Defense Fund; Michelle Passero, The Nature Conservancy Written Testimony: 8/11/2011 First 15-Day Changes Comment #: 1120
CBD5	Brian Nowicki and Kevin Bundy Affiliation: Center for Biological Diversity Written Testimony: 9/27/2011 Second 15-Day Comment # 2093

Commenter ID	Commenter Information
CBE1	Adrienne Bloch Affiliation: Communities for a Better Environment Written Testimony: 12/14/2010 45-Day Comment #: 762
CIPA	Norman Plotkin Affiliation: California Independent Petroleum Association Written Testimony: 8/11/2011 First 15-Day Changes Comment #: 1134
CRPE1	Sofia Parino, Center on Race, Poverty and the Environment; Tom Frantz, Association of Irritated Residents; Penny Newman, The Center for Community Action and Environmental Justice; Teresa DeAnda, El Comite para el Bienestar de Earlimart; Martha Guzman Aceves, California Rural Legal Assistance Foundation; Anna Yun Lee, Communities for a Better Environment; Jane Williams, California Communities Against Toxics; Nicole Capretz, Environmental Health Coalition Written Testimony: 12/14/2010 45-Day Comment #: 693
CRPE4	Sofia Parino, Center on Race, Poverty & the Environment; Maria Covarrubias, Comité ROSAS; Domitila Lemus, Comité Unido de Plainview; Maria Buenrostro, Comité Luchando por Frutas y Aire Limpio; Penny Newman, the Center for Community Action and Environmental Justice; Linda Mackay, TriCounty Watchdogs; Jesse Marquez, Coalition for a Safe Environment; Angela Meszros; Strela Cervas, California Environmental Justice Alliance; Tom Frantz, Association of Irritated Residents; Salvador Partida, Committee for a Better Arvin; Ruth Martinez, Comité Si Se Puede; Ana Ceballor, La Voz de Toniville; Teresa DeAnda, El Comité Para El Bienestar de Earlimart; Gary Lasky, Sierra Club Tehipite Chapter; Shabaka Heru, Society for Positive Action; Caroline Farrell Written Testimony: 8/11/2011 First 15-Day Comment #: 1110
DWR	Veronica Hicks Affiliation: California Department of Water Resources Written Testimony: 12/15/2010 45-Day Comment #: 728

Commenter ID	Commenter Information
DWR2	Veronica Hicks Affiliation: Department of Water Resources Written Testimony: 8/11/2011 First 15-Day Changes Comment #: 1107
DWR3	Veronica Hicks Affiliation: Department of Water Resources Written Testimony: 9/27/2011 Second 15-Day Changes Comment #: 2064
FRIENDSOFEARTH2	Kate Horner, Friends of the Earth US; Rolf Skar, Greenpeace; Victor Menotti, International Forum on Globalization; Bill Barclay, Rainforest Action Network Written Testimony: 8/11/2011 First 15-Day Changes Comment #: 1175
HDDP2	Bradley K. Heisey Affiliation: High Desert Power Project Written Testimony: 12/14/2010 45-Day Comment #: 617
NCPA3	Susie Berlin Affiliation: McCarthy & Berlin, P.C. for Northern California Power Agency Written Testimony: 8/11/2011 First 15-Day Changes Comment #: 1176
NRDC4	Alex Jackson Affiliation: Natural Resources Defense Council Written Testimony: 12/16/2010 45-Day Comment #: 958
SACREB	Karen Klinger Affiliation: Sacramento Real Estate Broker Written Testimony: 12/16/10 First 15-Day Changes Comment #: 983
PCAPCD2	Name: Thomas Christofk Affiliation: Placer County Air Pollution Control District Written Testimony: 8/11/2011 First 15-Day Changes Comment #: 1051

Commenter ID	Commenter Information
USFLAW	Alice Kaswan Affiliation: University of San Francisco School of Law Written Testimony: 12/10/2010 45-Day Comment #: 486
VALERO2	Matthew H. Hodges for Patrick Covert Affiliation: Valero Companies Written Testimony: 8/11/2011 First 15-Day Changes Comment #: 1062

Location of Comment Letters on the ARB Website

All comment letters and attachments received on the proposed Cap-and-Trade Regulation are posted on the ARB website at the following link: http://www.arb.ca.gov/lispub/comm/bccommlog.php?listname=capandtrade10

To manually locate the comments on the ARB website:

- Go to www.arb.ca.gov
- Select "Climate Change Program" in the left column
- Under "Assembly Bill 32 Implementation and Other Activities", Select "Cap-and-Trade Program" on the activities tab
- Select "View All Public Comments" in the right column.

On the website, the comments are ordered by date received grouped by review period, i.e. 45-Day, first 15-Day changes (15-1), or second 15-Day changes (15-2).

COMMENTS AND RESPONSES

This section summarizes comments on the Draft FED and presents ARB's responses to those comments. The comments identified in this CEQA document are a subset of all comments received on the proposed Cap-and-Trade Regulation. Comments that do not pertain to the adequacy of the environmental analysis are addressed in the Final Statement of Reasons (FSOR) prepared as part of the rulemaking process.

In this Response to Comments document, individual comments are presented under the correspondence within which they were received, ordered alphabetically by COMMENT ID and identified as follows:

COMMENT ID: *This is the abbreviation used to identify the comment correspondence in which the individual comments are contained.*

Name:	*Person(s) submitting the comment*
Affiliation:	*Affiliation of the commenter(s)*
Written Testimony: M/D/Y	*Type of comment and date received*
45-Day Comment #: 123	*Comment period and unique comment number. The unique ID number corresponds to numbering in the FSOR.*

Comment: *Comments received under the COMMENT ID are presented individually as shown in this example, beginning with* ***Comment*** *on the first line.*

> **Response:** *Responses are presented following each comment. Responses are indented from the left margin.*

Comment: *All of the individual comments received under the COMMENT ID are presented as demonstrated in this example. This comment would be followed by subsequent comments from this commenter.*

> **Response:** *Responses are presented following each comment. Responses are indented from the left margin.*

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BLUESOURCE

Name: Roger Williams
Affiliation: Blue Source
Written Testimony: 12/13/2010
45-Day Comment #: 660

Comment: The Forest Carbon Developers support ARB's draft market rules and the forest project protocol in general. However, we view the proposed rules as improperly restrictive in ways that make them arbitrary or unnecessarily burdensome and expensive. In these instances, the proposed Regulation does not constitute a reasonable and rational choice, and therefore should be revised consistent with the comments below in order to be legally valid and consistent with the mandate of AB 32 under the California Administrative Procedure Act (APA) and/or the California Environmental Quality Act (CEQA). (BLUESOURCE)

> **Response:** This comment summarizes the commenter's more detailed comments provided later in the letter. See responses prepared to the applicable BLUESOURCE comments.

Comment: As a matter of environmental policy and review, ARB has failed to consider that disqualifying early-mover projects will likely result in the abandonment of those projects, thus not only increasing greenhouse gas emissions but also losing the other societal benefits provided by forest conservation projects, such as habitat and watershed protection. Although ARB recognizes its duty under AB 32 to consider overall societal benefits, including reductions in other air pollutants and other benefits to the economy, environment and public health, the Agency has failed to justify why its arbitrary date restriction is defensible in light of AB 32's mandate or why an earlier start date is not an acceptable alternative.

APA requires ARB to prepare a description of reasonable alternatives to the proposed Regulation and the agency's reasons for rejecting those alternatives, and to determine in its final statement of reasons that no alternative considered by the agency would be more effective in carrying out the purpose for which the Regulation is proposed or would be as effective and less burdensome to affected private persons than the adopted regulation. Similarly, Health & Safety Code section 57005 requires ARB to evaluate the alternatives and consider whether there is a less costly alternative or combination of alternatives which would be equally as effective in achieving increments of environmental protection in a manner that ensures full compliance with statutory mandates within the same amount of time as the proposed regulatory requirements. APA also requires consideration of alternatives for reducing impact on small businesses, such as the Forest Carbon Developers. Although quantification protocols are exempt from APA pursuant to AB 32, HSC section 38571, the issues raised herein are related to non-quantification eligibility criteria, which are subject to APA strictures. ARB also failed to consider these alternatives in its CEQA functional equivalent document. (BLUESOURCE)

Response: The commenter suggests that disqualifying early-mover projects will likely result in the abandonment of those projects, thus not only increasing GHG emissions but also losing the other societal benefits provided by forest conservation projects, such as habitat and watershed protection.

We disagree that the proposed Regulation would result in the abandonment of early-mover projects. The Regulation includes a process for accepting offset credits from qualified existing offset projects into the ARB compliance offsets program. This not only recognizes and rewards these actions, it also helps create an initial supply of offset credits for the cap-and-trade program. We do not agree with accepting offsets from projects before 2005 because beginning in 2005, the Climate Action Reserve (CAR) and its predecessor, the California Climate Action Registry, began adopting voluntary GHG accounting protocols to encourage voluntary early action to reduce GHG emissions. To ensure the GHG reductions and GHG removal enhancements being used in the compliance program are real and additional, we chose to implement the January 1, 2005, date to correspond with the adoption of voluntary offset protocols as the eligible date for transition of early action offset credits to ARB offset credits.

That said, early action offset projects that began prior to January 1, 2005 are still allowed to come into the compliance program and receive early action offset credits for reductions that they achieve between January 1, 2005 and December 31, 2014. To clarify this point we added a new section, 95973(c), that allows a commencement date prior to December 31, 2006 for early action offset projects that transition to Compliance Offset Protocols pursuant to section 95990(k). Any reductions achieved before 2005 may still be traded and sold in the voluntary market but will not be recognized by ARB or allowed to be used for compliance.

In response to the commenter's second point, for projects developed under CAR protocols, we believe that January 1, 2005, is the appropriate date to credit the early voluntary GHG reductions and GHG removal enhancements because it reflects the timeframe in which the voluntary protocols were approved by CAR. If ARB decides to accept early action offset credits achieved under other protocols not developed by CAR, ARB will evaluate whether another date is appropriate for those credits and amend the Regulation if necessary.

In response to the commenter's third point, we added new section 95990(k) to clarify how early action offset projects transition to Compliance Offset Protocols. New section 95990(k)(2) clarifies that once an early action offset project transitions to a Compliance Offset Protocol it will begin an initial crediting period. The crediting period under the early action offset program does not count under the compliance offset program, so the early action offset project may transition any time before February 28, 2015, but must list or register with an Early Action Offset Program by January 1, 2014, (section 95990(c)(3)) to get early action offset credits. This provides a seamless transition process for early action offset projects and guarantees them a new crediting period. It is necessary for offset projects beginning February 28, 2015, to transition to Compliance Offset Protocols to ensure consistency in the program. It is also necessary that all offset projects are following the rules of the Regulation, including the rules in the Compliance Offset Protocols. We believe that this process will incentivize early action offset projects to transition to Compliance Offset Protocols, and that it will not penalize them.

Based on the preceding explanation, the Regulation would not result in the abandonment of early-mover projects, and as such would not increase GHG emissions that could occur as a result of such abandonment.

The commenter asserts that ARB failed to consider the alternatives required by the APA and HSC in its CEQA functional equivalent document. ARB examined a reasonable range of alternatives, as required under CEQA. The commenter is referred to the description of CEQA alternatives provided as a response to CRPE1. Non-CEQA aspects of this comment are addressed in the FSOR prepared in accordance with APA requirements.

Comment: ARB's requirement that forest owners commit to restricting land-use for 100 years following the issuance of the last offset credit has not been justified by ARB either as a matter of policy or science. In our experience, this arbitrary requirement has become in practice a major obstacle to implementing forest projects, since few landowners are willing to commit land to a certain use for such an extended period for uncertain economic returns. Thus, ARB's policy is deterring beneficial projects and reducing potential environmental and social benefits. Other forest protocols, such as those developed by ACR and VCS do not impose such an unjustified temporal restriction. ARB fails to adequately examine the scientific, policy and environmental bases for this extended requirement, and thus this requirement is contrary to the APA and CEQA. Rather than demanding that land use be restricted for 100 years, the landowner commitment should be commensurate with the length of the regulatory program, and any adjustment for early withdrawal from a commitment should be proportional to the remaining atmospheric benefit of sequestered carbon. We look forward to working with ARB to refine the rules in this respect. (BLUESOURCE)

Response: Ensuring permanence is essential to the environmental integrity of the entire cap-and-trade program. Because offsets allow for an equivalent quantity of GHG emissions within the capped sectors, the CO_2 stored in biological sinks resting from offset project activities must stay out of the atmosphere for a time period comparable to the emissions they are offsetting. If they do not, the net effect would be an increase in GHG emissions to the atmosphere. Scientific estimates of the atmospheric lifetime of anthropogenic CO_2 emissions are uncertain, as CO_2 is removed from the atmosphere by a number of processes that operate at different timescales. However, 100 years should be viewed as a minimum time period for maintaining permanence because a fraction of anthropogenic CO_2 is expected to remain in the atmosphere well beyond 100 years as it is gradually removed through processes such as silicate weathering. The period of 100 years is frequently used in international climate change policy as a standard frame of reference for determining global warming potentials and setting GHG emission reduction targets, and consequently the use of 100 years to define the permanence of reductions is consistent with other programs.

This requirement was evaluated in the FED. No adverse environmental effects were identified as resulting from this requirement and none are offered by the commenter. Therefore, ARB believes the impact analysis appropriately considers this issue and no changes to the FED are warranted. Non-CEQA aspects of this comment are addressed in the FSOR prepared for the Regulation in accordance with APA requirements.

CBD1

Name: Brian Nowicki and Kevin Bundy
Affiliation: Center for Biological Diversity
Written Testimony: 12/15/2010
45-Day Comment # 746

Comment: The Functional Equivalent Document ("FED") containing ARB's analysis of the environmental impacts of the proposed Regulation also fails to disclose, analyze, and propose mitigation for significant environmental impacts, and fails to adequately discuss a range of reasonable alternatives that could avoid these impacts. (CBD1)

> **Response:** The commenter is referred to the discussion of alternatives provided as a response to CRPE1. ARB examined a reasonable range of alternatives, as required under CEQA. At the programmatic level, the fundamental purpose of the alternatives analysis is to determine if other broad program approaches, such as direct regulation or adoption of a carbon fee, might achieve the project objectives and lessen or avoid the potential adverse environmental impacts attributed to the proposed project.
>
> The Forest Offset Protocol is a part of the proposed Cap-and-Trade Regulation. The alternatives do not focus on a single sector (such as food processing) or a single action (such as facility relocation), because this would be too narrowly defined to achieve the AB 32 GHG reduction goal. Development of the proposed Regulation is an ongoing process which reflects changes and suggestions received through public and stakeholder participation. In response to this specific concern, the commenter is directed to the revised regulation which reflects substantial changes to the general offset sections of the Regulation and the Forest Offset Protocol, increasing the stringency of the offset requirements, which should reduce concerns about potential adverse environmental impacts. Nonetheless, the FED takes the conservative approach in its post-mitigation significance conclusion and discloses, for CEQA compliance purposes, that some of the impacts associated with forestry operations are considered potentially significant and may be unavoidable. The commenter is referred to the discussion of adaptive management provided as a response to CBE1.

Comment: The proposed regulation fails to maximize environmental co-benefits to the extent feasible. Prior to adopting a Cap and Trade system under AB 32, ARB must, "to the extent feasible," maximize additional environmental benefits to California where it is appropriate to do so. Health and Safety Code section 38570(b)(3). By using the term "feasible," the Legislature signaled its intent to require ARB to demonstrate that all appropriate measures must be taken to maximize environmental benefits, unless those measures are shown to be impracticable.

AB 32 does not define the term "feasible." However, that term has a specific meaning under other statutes, including the California Environmental Quality Act—a meaning of which the Legislature was presumptively aware when it enacted AB 32. "Feasible" means “capable of being accomplished in a successful manner within a reasonable period of time, taking into account economic, environmental, social, and technological factors.” Pub. Res. Code section 21061.1. In the CEQA context, when a lead agency rejects an alternative as economically infeasible, it must support that determination with quantitative, comparative evidence that the alternative would be economically impracticable (not just more expensive). See, e.g., Save Round Valley Alliance v. County of Inyo, 157 Cal. App. 4th 1437, 1461-62 (2007) (holding that applicant’s inability to achieve “the same economic objectives” under a proposed alternative does not render the alternative economically infeasible); Uphold Our Heritage v. Town of Woodside, 147 Cal. App. 4th 587, 600 (2007) (requiring evidence that comparative marginal costs would be so great that a reasonably prudent property owner would not proceed with the project); Preservation Action Council v. City of San Jose, 141 Cal. App. 4th 1336, 1356-57 (2006) (holding that evidence of economic infeasibility must consist of facts, independent analysis, and meaningful detail, not just the assertions of an interested party). Nor may a lead agency conclude that mitigation measures are legally infeasible without an adequate basis. As the Supreme Court put it, “[a]n EIR that incorrectly disclaims the power and duty to mitigate identified environmental effects based on erroneous legal assumptions is not sufficient as an informative document.” City of Marina v. Bd. of Trustees, 39 Cal. 4th 341, 356 (2006).

The Legislature’s use of the term “feasible” in connection with environmental co-benefits thus imposes a specific burden on ARB—a burden that the ISOR and FED fail to meet. For many months, the Center and other organizations have identified specific, appropriate measures to ARB staff (such as, for example, measures to ensure that forest offset projects improve forest management rather than perpetuate environmentally destructive practices) that could enhance, and thus help maximize, environmental co-benefits. Many of those measures are discussed again throughout this letter. At no point, however, has ARB demonstrated the infeasibility, or even the inappropriateness, of any of these measures. The Cap and Trade regulation as proposed thus fails to comply with AB 32. (CBD1)

> **Response:** The commenter states that ARB has not demonstrated that specific measures suggested by the commenter and other groups that could help maximize environmental co-benefits (such as measures to ensure that forest offset projects improve forest management) are infeasible as required by Health and Safety Code (HSC) section 38570(b)(3). The provision cited directs ARB to: “to the extent feasible and in furtherance of achieving the statewide greenhouse gas emissions limit…maximize additional environmental benefits.” (HSC 38570(b)(3).). AB 32 does not include a specific definition of “feasible” or criteria that should be used to determine what constitutes “to the extent feasible.” AB 32 leaves the specifics of how to do so, including balancing a variety of competing concerns, up to ARB. During development of the Cap-and-Trade Regulation, ARB considered all of its statutory mandates under AB 32, including the requirement to consider measures to maximize additional environmental benefits based on evidence, including economic analysis, where appropriate “to the extent feasible and in furtherance of achieving the statewide greenhouse gas

emissions limit." The appropriate analyses are included within the ISOR for the Regulation. ARB does not interpret AB 32 to require ARB to make a formal infeasibility determination regarding specific measures suggested by the commenter and other groups.

Development of the proposed Cap-and-Trade Regulation included extensive economic analysis and the involvement of an Economic and Allocation Advisory Committee. The updated economic analysis supporting the development of the Regulation was prepared by ARB and released on March 24, 2010 (ARB 2010). Economic reasons were not cited for potential infeasibility of avoiding impacts from implementing the proposed Forest Offset Protocol. On pages 311 to 314 of the FED, ARB explains that significant adverse biological impacts are not expected from implementing the Forest Offset Protocol, because sustainable, long-term harvesting practices and natural forest management would be required and project sites would be subject to some silvicultural activities with or without a Forest Offset Protocol project. Nonetheless, the FED discloses the risk that some adverse impacts cannot be entirely eliminated and unanticipated adverse biological impacts could occur. ARB cannot speculate as to the location of such impacts, but has committed to implementing an adaptive management approach as a program design feature that affords adjustment to the Regulation if any unanticipated significant biological impacts occur. These limits are well defined in authorizing legislation for ARB's responsibilities, which do not include regulation of biological or other non-air related natural resources. This conservative assessment of the situation (i.e., tending to overstate impacts) is intended to fulfill ARB's disclosure duties under CEQA.

Non-CEQA aspects of this comment, such as APA or AB 32 requirements, are addressed in the FSOR prepared for the Regulation in accordance with APA requirements.

Comment: The FED fails to comply with the California Environmental Quality Act (CEQA), Public Resources Code section 21000 et seq., and the CEQA Guidelines, title 14, California Administrative Code, section 15000 et seq. ARB's program for adopting air quality regulations is a "certified regulatory program" for CEQA purposes. (CEQA Guidelines section 15251(d)). Accordingly, the FED must include a description of the proposed Regulation, along with alternatives and mitigation measures to minimize any significant adverse effect. Pub. Res. Code section 21080.5(d)(3); Schoen v. Dept. of Forestry, 58 Cal. App. 4th 556, 566-67 (1997). Although ARB's regulatory program is exempt from certain requirements generally applicable to environmental impact reports under CEQA, see Sierra Club v. Bd. of Forestry, 7 Cal. 4th 1215, 1229-30 (1994), the core procedural and substantive provisions of CEQA still apply. In particular, ARB may not approve a regulation if there are feasible mitigation measures or alternatives available that would lessen or avoid its significant environmental effects. See Pub. Res. Code sections 21002, 21002.1(b), 21081.

As a general matter, the FED is quick to disclaim any responsibility for implementation of measures to mitigate the potentially significant economic impacts of the cap-and-trade program. The FED repeatedly states that other agencies will be responsible for implementing those measures at the project level, see, e.g., FED at 130, but fails to demonstrate in each instance that ARB lacks any legal authority to implement mitigation at the program level. If ARB can feasibly take steps to mitigate any specific effects of this action, it must do so; it may not shift this responsibility to other agencies as a general rule. Cf. City of Marina, 39 Cal. 4th at 366-67.

The FED also relies as a general matter on impermissibly deferred mitigation in the form of "adaptive management." The FED acknowledges that the cap-and-trade program may create perverse incentives and lead to potentially significant environmental impacts. Rather than proposing measures to ameliorate those impacts as CEQA requires, however, the FED states that ARB will monitor a few limited sources of information and develop "appropriate" responses if some unidentified level of impact materializes at some point in the future. See FED at 43-51, 311-14. "Formulation of mitigation measures should not be deferred until some future time." CEQA Guidelines section 15126.4(a)(1)(B). If mitigation is deferred, CEQA requires a lead agency both to develop specific performance standards and to commit to specific mitigation actions that will be taken if those standards are not met. Id.; see also, e.g., Gray v. County of Madera, 167 Cal. App. 4th 1099, 1118-19 (2008); Endangered Habitats League v. County of Orange, 131 Cal. App. 4th 777, 793-94 (2005) (agency "goes too far" when it requires only that project proponent obtain a "report" and then comply with recommendations in the report). The FED's promises of "adaptive management" fail to meet these standards. Under the FED's "adaptive management" strategy, moreover, ARB would take unspecified "appropriate" actions only if future, unanticipated environmental consequences "interfere with or undermine" the objectives of the cap-and-trade program. See FED at 46, 47, 313. Notably, the "adaptive management" strategy does not commit ARB to taking "appropriate" action in the event that significant, unanticipated environmental impacts occur. The purpose of mitigation under CEQA is to reduce or avoid significant environmental impacts, not to advance the objectives of other legislative programs. Accordingly, the "adaptive management" strategy cannot be considered mitigation under CEQA because it does not respond to the impacts that CEQA was designed to avoid.

Finally, the adaptive management strategy is not designed to gather the information that would enable ARB to detect, much less respond to, unanticipated environmental impacts. In the air quality context, for example, ARB proposes to monitor greenhouse gas emissions from covered sources. FED at 46-47. A major concern with the cap-and-trade program, however, is that emissions trading will result in increased local concentrations of conventional and toxic pollutants; information on greenhouse gas emissions alone may not reveal whether such increases are occurring. The FED also proposes to "solicit information" from local air districts concerning new and modified permits, and to evaluate this information at least once per compliance period (i.e., once every three years). FED at 47, 51. This information, however, will not contain data on pollution increases that fall below permitting thresholds. Nor will this information capture pollution increases associated with increasing production to limits in existing permits. Nor will a triennial review disclose pollution increases in time to develop an "appropriate" response.

In sum, the FED's "adaptive management" strategy will not prevent significant environmental effects, and will not permit ARB to respond to unanticipated effects in a timely or effective manner. Absent specific performance standards, timely and rigorous monitoring of all relevant information, and particularized responses to triggering events, "adaptive management" remains little more than a smokescreen for inadequate analysis of environmental impacts. (CBD1)

Response: The commenter argues that ARB has the responsibility to require project-specific mitigation, and that the FED relies on deferred mitigation in the form of an adaptive management approach. Specifically, the commenter states that the adaptive management approach identified in the FED does not commit ARB to take appropriate action in the event significant impacts occur in the future.

The proposed cap-and-trade regulation would require GHG reductions on a statewide level, but would not stipulate specific improvements or compliance actions by individual regulated entities. As such, it is not possible to ascertain how individual entities may choose to comply. The environmental impact analysis prepared for the proposed Cap-and-Trade Regulation evaluates reasonably foreseeable compliance responses at the programmatic level, and does not speculate as to what actions may be undertaken by individual entities. The FED recognizes that most reasonably foreseeable compliance responses entail some level of onsite construction or installation activities that are traditionally subject to local regulations. ARB does not have the regulatory authority to require and/or permit facility-specific improvements. Local air pollution control districts and/or air quality management districts (air districts) have primary responsibility for adoption and implementation of stationary and area-wide source emission control measures. The FED accurately reflects that local governments, notably cities and counties, have land use and permitting authorities (CEQA lead agency authority, zoning ordinances and regulations, building codes, construction permits, etc.) that are applicable to facility-specific projects. Such projects may be undertaken as compliance responses and would be local improvements subject to project-level CEQA analysis and local permitting.

The FED identified ARB's commitment to an adaptive management approach to assess the effectiveness of the Regulation, and identify data trends that could indicate unanticipated or undesirable results, or a need for changes to ensure the Regulation is meeting its objectives. This monitoring and feedback approach is a fluid process that evolves in response to results observed over time. ARB staff is proposing that the Board adopt an adaptive management plan that lays out a framework for an adaptive management approach to monitor the potential for adverse impacts that could result from action taken to comply with the proposed Regulation. The plan will focus on the potential for localized air quality impacts and the potential for adverse forestry impacts resulting from the Forest Protocol.

The proposed adaptive management approach has certain attributes of mitigation, in that it can result in the reduction or elimination of potential adverse impacts for the proposed Cap-and-Trade Regulation. However, adaptive management is being proposed to be incorporated as an integral design feature of implementation of the proposed program. As such, the adaptive management approach is not "deferred mitigation." Furthermore, in the context of mitigation in CEQA, the courts have upheld project approvals where the formulation of precise mitigation is infeasible because the exact nature of potential impacts is not known at the time of project approval. Mitigation strategies have been upheld when the agency commits itself to eventually devising measures in accordance with specific performance criteria articulated at the time of project approval. (See *Sacramento Old City Assn. v. City Council* (1991) 229 Cal. App. 3d 1011, 1028-29.) By analogy, staff's proposed adaptive management plan describes ARB's commitment to a specific process, including an analysis of available data, triggers for further analyses to determine whether there are localized air quality impacts or adverse forestry impacts, and if impacts are identified, the process for devising specific mitigation measures. By analogy to mitigation strategies in CEQA, the adaptive management plan lays out ARB's performance standard for identifying and addressing these potential adverse impacts identified in the FED. If the proposed Cap-and-Trade Regulation is approved, this plan would be implemented based on direction from the Board.

Comment: The Forest Offset Protocol proposed in the Cap-and-Trade Regulation is nearly identical to the Forest Project Protocol prepared by the Climate Action Reserve. For example, as previously discussed, the Forest Offset Protocol continues to allow and incentivize even-aged management practices such as clear-cutting that imperil forest health, water quality, and biodiversity; continues to provide incentives for conversion of native forests to plantations; continues to contain loopholes that incentivize increased short-term logging (and associated GHG emissions); and continues to offer credits for non-additional forest management activities in a manner that could increase overall GHG emissions. The impacts associated with these incentives and loopholes have been detailed in a series of letters from the Center to both the Climate Action Reserve and ARB over the past year. The FED largely fails to address the specific impacts identified in this series of letters. Accordingly, the arguments raised in those letters apply with equal force to the Forest Offset Protocol proposed in connection with the cap-and-trade program. These letters are therefore attached and incorporated by reference.

The FED attempts to dismiss concerns that the Forest Offset Protocol will incentivize clear-cutting and conversion of native forests on the theory that such practices will not significantly increase carbon storage. FED at 304-05. The conclusion is dubious, and contradicted by the record of protocol development; throughout the Climate Action

Reserve's protocol development process, timberland owners and other prospective forest project proponents repeatedly insisted that clearcutting and conversion of mature, uneven-aged forests were necessary to maximize carbon sequestration. This conclusion also is purportedly based on a study of "several California forest types." Id. at 304. However, the Forest Offset Protocol applies not just in California, but throughout the continental United States. Thus the FED is devoid of any analysis as to whether the Forest Offset Protocol will incentivize clearcutting and conversion of native forests outside California. Indeed, the FED acknowledges that out-of-state projects may not be subject to the level of environmental analysis that would accompany California or federal projects. Id. at 306. The FED's conclusions that the Forest Offset Protocol will not incentivize clearcutting and conversion lack support.

Despite these conclusions, the FED acknowledges that the Forest Offset Protocol may significantly affect biological resources. FED at 313-14. The FED proposes that ARB mitigate these effects by implementing "adaptive management." As previously discussed, "adaptive management," as proposed in the FED, does not constitute effective or legally permissible mitigation for these foreseeable impacts.

In any event, it is unlikely that the adaptive management program proposed in the FED would allow ARB even to detect, much less ameliorate, the adverse consequences of the Forest Offset Protocol. The FED proposes to collect information only from annual project verification reports and from "periodic" solicitation of public and stakeholder comments. FED at 313. This information, however, will not reveal whether project proponents changed management strategies, in response to the availability of offset credits, in a manner destructive of biological or forest resources. At the very least, a more credible adaptive management program would need to collect a great deal of additional information concerning historical harvest practices at the ownership and landscape scale, changed management practices following enrollment of projects under the Forest Offset Protocol, and continuous monitoring of ecological indicators (including species population trends and water quality) on project lands. The program also would have to establish specific benchmarks or performance standards for example, a certain amount of natural forest converted to plantations, or a certain amount of uneven-aged forest converted to clearcut rotations that would trigger specific ameliorative responses. Absent adequate information, specific performance thresholds, and particularized responses, the FED's "adaptive management" program cannot function as a mitigation measure for the Forest Offset Protocol. (CBD1)

> **Response:** The FED fully analyzed the potential for adverse impacts resulting from the Forest Protocol. The Forest Offset Protocol would not allow any forest management activity that is not allowed by state, federal, or local laws and regulations. The Forest Offset Protocol includes environmental safeguards to help assure the environmental integrity of forest projects. These include requirements for projects to demonstrate sustainable long-term harvesting practices, limits on the size and location of even-aged management practices, and requirements for natural forest management that require all projects to utilize

management practices that promote and maintain native forests comprised of multiple ages and mixed native species at multiple landscape scales.

In accordance with these requirements, the Forest Offset Protocol is not expected to increase the size of even-aged harvested areas or to result in plantation forests. Furthermore, modeling forest growth, mortality, and harvesting over time indicate that it would be unlikely for a forest project to remain eligible (i.e., demonstrate a continued net reduction in carbon sequestration), if conversion to a single-species, single-aged plantation occurred (FED, page 304).

The cap-and-trade program is made up of many elements, must serve a large number of important objectives, and relies on the actions of a large number of participants operating in a complex market system. Therefore, unanticipated effects could occur over the life of the program. The Forest Offset Protocol in particular has been identified as potentially resulting in unexpected environmental effects on forest ecosystems and biological resources (e.g., creating incentives for less environmentally conservative management practices). Based on the available data and current law and policies that regulate forest activities, ARB concludes that substantial impacts from forest project-related impacts attributable to the proposed cap-and-trade program are unlikely. However, there is at least a possibility that some unintended impacts could occur. Accordingly, the FED takes the conservative approach in its post-mitigation significance conclusion and discloses, for CEQA compliance purposes, that some of the impacts associated with compliance responses and forestry operations are considered potentially significant and may be unavoidable.

See response to CBD1 regarding staff's proposed adaptive management plan to assess the effectiveness of the Protocol and ARB's commitment to a specific process for identifying data trends that could indicate unanticipated adverse results, triggers for further analyses to determine if impacts are result of the Protocol design, and if impacts are identified, the process for devising specific mitigation measures, such as changes to the Protocol.

Comment: The FED fails to disclose, analyze, and propose mitigation for impacts related to the biomass and biofuels exemption. Adoption of a regulation is a "project" for CEQA purposes, and the courts have recognized that CEQA requires analysis of environmental impacts associated with a regulation that creates incentives for particular actions. See Cal. Unions for Reliable Energy v. Mojave Desert Air Qual. Mgmt. Dist., 178 Cal. App. 4th 1225, 1244-45 (2009). The FED here completely fails to disclose, analyze, or propose mitigation for the reasonably foreseeable and likely significant effects of exempting all biomass and biofuels emissions from compliance obligations.

This exemption creates a strong incentive to burn biomass fuels in at least two ways. First, emissions from biomass and biofuels combustion do not give rise to any compliance obligation, and thus will not require purchase or retirement of allowances or offsets. This will encourage use of biogenic fuels wherever fuel-switching is cheaper than the purchase of allowances or offsets.

Second, the biomass and biofuels exemption leaves a number of facilities that already use these fuels outside the cap. Those facilities, however, could choose to “opt in” to the program for the purpose of obtaining allowances. See Proposed Reg. Section 95813. Emissions from those facilities would be evaluated against an “efficiency benchmark” based on natural gas combustion. ISOR at II-31. According to the ISOR, “if a facility used a cleaner fuel source, like biomass, or combusts the fuel more efficiently, it would be rewarded with more allowances relative to its actual emissions.” Id. (emphasis added). This not only assumes without any support that biomass combustion is “cleaner” than natural gas, but also creates a strong incentive for biomass-fueled facilities to “opt in” to the cap-and-trade program for the purpose of obtaining valuable allowances while at the same time escaping any compliance obligation. See Proposed Reg. Sections 95812(a), 95852.2. The proposed rules thus potentially create a double “freebie” for biomass combustion: an exemption from compliance obligations, coupled with a program for distributing free allowances for that same combustion that may be sold into the market and used to justify emissions at other facilities. This double “freebie” not only incentivizes biomass and biofuels use but also risks a form of allowance double-counting that could ultimately increase GHG emissions overall.

The FED fails to disclose, analyze, and propose mitigation for the foreseeable effects of these incentives. Indeed, the FED completely fails to discuss many of the foreseeable impacts of incentivizing “decarbonization” compliance pathways involving biomass and biofuels. The only oblique mention of such impacts is in the context of cement plants using old tires to fire kilns (a process by which the natural rubber portion of the tires could be “credited as biomass”). FED at 153. Other foreseeable compliance pathways involving biomass and biofuels combustion are simply not discussed. The FED similarly contains no analysis of the impacts of incentivizing these pathways on forest resources, biological resources, geology and soils, or water quality— even though creating an incentive for biomass usage will foreseeably increase biomass harvests. This is a glaring and unlawful omission.

Burning trash, tires, and wood in place of other fuels may increase local emissions of criteria and toxic pollutants. Large-scale replacement of other energy sources with biomass will also put increased pressure on forest ecosystems, with resultant impacts on biodiversity, water quality, and forest health. The potential for these impacts is well-documented; indeed, one recent study concludes that a wide-scale shift to woody biomass energy generation could eventually result in conversion of nearly all of the world’s unmanaged forests and much of its pastureland to energy plantations. Significant impacts associated with increased biomass usage may already be anticipated to result from renewable energy standards and a plethora of state and federal subsidies for biomass development. In this context, an exemption from compliance obligations for biomass emissions under the cap-and-trade program at the very least constitutes a considerable contribution to a cumulatively significant effect. The FED fails to consider this.

Finally, the FED fails to adequately address the effects of the biomass exemption on overall greenhouse gas emissions. The document concludes that switching to "less carbon- intensive" fuels will produce a "beneficial effect" in terms of greenhouse gas emissions. FED at 184. Yet the core assumption underlying this conclusion that biomass emissions are "carbon neutral" is both unstated and unsupportable. Accordingly, biomass and biofuels may not be "less carbon-intensive" than the fuels or energy sources they replace, especially over the time frame relevant to AB 32, and especially if the replaced sources come from other potentially more costly renewables like wind and solar. Absent a protocol for tracking the sources of biomass fuels, evaluating the carbon debts associated with particular fuel sources, and reaching a defensible conclusion as to the real carbon footprint of biomass, the FED cannot rationally conclude that the biomass exemption confers an environmental benefit. (CBD1)

> **Response:** The commenter states that the FED failed to analyze the impacts of and propose mitigation for the exemption of biomass and biofuels emissions from compliance obligations. ARB disagrees with the commenter. The Updated Economic Evaluation of California's Climate Change Scoping Plan, which includes a cap-and-trade program, used the ENERGY 2020 model to assess the potential changes in energy use, both type and volume, brought on by the proposed Cap-and-Trade Regulation. The model did not indicate that the use of biomass would increase in response to the proposed Cap-and-Trade Regulation, and accordingly such an increase was not identified as an impact in the FED. The explanation for why the proposed Regulation would not have an effect is that increased use of biomass is already incentivized by existing regulations such as the Renewables Portfolio Standards and the Low Carbon Fuel Standard. The Renewables Portfolio Standard (RPS) requires publicly owned utilities to obtain 33% of their energy from renewable resources, including biomass. Most utilities are challenged to achieve the renewable target despite the availability of biomass as a renewable fuel. Increased use of biomass for energy generation created by other state policies and initiatives, such as the Renewable Portfolio Standard, is discussed in the FED (see pages 351-352).

Comment: Under CEQA, the FED must consider a range of reasonable alternatives that would feasibly attain most of the objectives of the Cap-and-Trade Regulation while avoiding or substantially lessening its significant impacts, and must compare the relative merits of these alternatives. CEQA Guidelines Section 15126.6(a). The FED fails to consider any alternative formulations of the Forest Offset Protocol that could meet these standards.

The Center and numerous other organizations have proposed alternative formulations to ARB throughout the past year. For example, ARB could have considered a version of the Forest Offset Protocol that eliminated clearcutting and other forms of even-aged management. ARB also could have considered restricting the conversion of uneven-aged, native forests to fast-growing plantations, and could have considered the inclusion of additional carbon pools. Finally, ARB could have considered a version of the protocol that corrected additionality problems caused by the protocol's failure to incorporate long-term sustained yield plans into the project baseline. These alternatives, alone or in combination, would have advanced many of the core objectives of the cap-and-trade program. Had ARB considered these alternatives, it could have compared them, alone or in combination, to the proposed Forest Offset Protocol, and evaluated their feasibility.

The FED failed to do so. Instead, the FED purports to have rejected "Environmental Performance Standards" for all compliance protocols. FED at 370. According to the FED, such standards are infeasible because: (a) they are unnecessary, given the existence of strong environmental laws in California; (b) they would be difficult to apply outside of California due to differences in local law; (c) it would be impossible to create performance standards that work across a wide range of project locations and conditions; and (d) implementing standards would create an administrative burden affecting the functioning of the offset market.

The FED's rejection of Environmental Performance Standards is puzzling at best and disingenuous at worst given that similar environmental standards already have been incorporated into every protocol ARB has proposed for adoption. These standards, such as the natural forest management requirement for forest projects and the limitation on clearcut size, have been applied regardless of California or local law, regardless of differences in project locations and conditions, and regardless of administrative burden. ARB cannot rationally reject alternative formulations of these standards as "infeasible" when the factors supposedly rendering them infeasible are common to the proposed project as well.

In order to reject an alternative as infeasible, the FED must set forth adequate quantitative, comparative data to enable the public and decision-makers to reach a rational conclusion. See, e.g., Save Round Valley Alliance, 157 Cal. App. 4th at 1461-62; Uphold Our Heritage, 147 Cal. App. 4th at 600. The FED does not even identify the particular "Environmental Performance Standards" that it supposedly finds infeasible, much less present adequate data and analysis in support of its conclusions. Accordingly, the FED's approach is unlawful, and the document must be revised to include discussion of a range of reasonable alternatives to Forest Offset Protocol design—including the alternatives identified above and in prior communications with ARB—that could ameliorate environmental effects while furthering AB 32's objectives. (CBD1)

> **Response:** The commenter suggests that the FED did not include a reasonable range of alternatives and states that ARB did not evaluate any alternatives to the Forest Offset Protocol. ARB disagrees. ARB examined a reasonable range of alternatives as required by CEQA and ARB's Certified Regulatory Program (CRP). Refer to the response presented under CRPE1 regarding the reasonable

range of alternatives considered in the FED. As described on page 368-370 of the FED, ARB evaluated five (5) alternatives to the cap-and-trade program. At the programmatic level, the fundamental purpose of the alternatives analysis is to determine if other broad program approaches, such as direct regulation or adoption of a carbon fee, might achieve the project objectives and lessen or avoid the potential adverse environmental impacts attributed to the proposed project. The Forest Offset Protocol is a part of the proposed Cap-and-Trade Regulation. The alternatives do not focus on a single sector (such as food processing) or a single action (such as facility relocation), because this would be too narrowly defined to achieve the AB 32 GHG reduction goal. Development of the proposed Regulation is an ongoing process that reflects changes and suggestions received through public and stakeholder participation.

The commenter is referred to the 15-Day revisions to the Regulation that increase the stringency of the offset provisions and Forest Offset Protocol requirements. Examples of proposed revisions include:

- Offset Project Operators or Authorized Project Designees must submit to California's jurisdiction to resolve disputes regardless of the physical location of the offset project.
- Additional attestations are required when an offset project is listed.
- The Offset Project Operator or Authorized Project Designee must disclose any offset credits issued for the same project for any other purposes in any other program.
- An offset verification team must review listing information submitted by the Offset Project Operator or Authorized Project Designee.
- A verification body must submit verification reports to Offset Project Registries with the Offset Verification Statement.
- Revision to the Compliance Offset Protocol U.S. Forest Projects disallows the use of Qualified Positive Offset Verification Statements because, for forest projects, ARB must ensure all protocol requirements are met, including sustainable harvesting requirements.
- Provisions have been added to deter forest project owners from terminating their offset projects early given permanence requirements that require the sequestration of carbon for 100 years. The Offset Project Operator or Authorized Project Designee must replace any reversed tons calculated pursuant to Compliance Offset Protocol, U.S. Forest Projects to ARB within 90 calendar days. If the Offset Project Operator or Authorized Project Designee does not replace the ARB offsets within the 90 days and ARB offset credits are retired from the Forest Buffer Account, ARB will assess penalties.

With regard to consideration of Environmental Performance Standards, the commenter recommends their use for the Forest Offset Protocol and expresses concern regarding ARB's conclusion that they would be infeasible as applied to the Cap-and-Trade Regulation. The FED explains on page 370 why the use of

Environmental Performance Standards is not feasible. The reasons are both practical (i.e., inability to cover the spectrum of potential sites and circumstances for Forest Offset projects) and legal (i.e., the potential for California-defined environmental standards to be inconsistent with the laws and regulations of other jurisdictions). Further, in California, defining Environmental Performance Standards is not necessary because criteria are established by existing environmental protection laws and regulations.

It is reasonable to expect adequate protection of environmental resources that are outside of the regular purview of ARB by relying on other applicable environmental laws and regulations within California and in other jurisdictions. Protection of other types of natural resources is best pursued by the agencies with jurisdiction over those resources, such as the Department of Fish and Game for California's wildlife. To attempt to create a separate set of standards specially applied to one type of forest activity (i.e., a forest offset project) could involve conflicts and inconsistencies with established regulatory programs, unnecessarily complicating forest management and resource protection.

ARB recognizes the importance of avoiding significant effects when implementing regulatory actions. To this end, see response to CBD1 regarding adaptive management.

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CBD4

Name, Affiliation: Nick Lapis, Californians Against Waste; Paul Mason, Pacific Forest Trust; Peter Miller, Natural Resources Defense Council; Brian Nowicki, Center for Biological Diversity; Timothy O'Connor, Environmental Defense Fund; Michelle Passero, The Nature Conservancy
Written Testimony: 8/11/2011
First 15-Day Changes Comment #: 1120

Comment: We understand that ARB expects the mitigation of environmental impacts resulting from the Cap and Trade Regulation to consist primarily of an adaptive management program, which in turn will largely rely on the information collected pursuant to the Mandatory Reporting Rule. As we stated in our comments to the Cap and Trade Regulation and associated FED, such an approach constitutes impermissibly deferred mitigation under CEQA. If mitigation is deferred, CEQA requires a lead agency both to develop specific performance standards and to commit to specific mitigation actions that will be taken if those standards are not met. As proposed in the proposed modifications, the Cap and Trade Regulation still lacks legally required performance standards and commitments to specific mitigation actions. Indeed, without these benchmarks and performance standards, it is impossible to determine even what information must be collected. Neither the Cap and Trade Regulation nor the Mandatory Reporting Rule identifies benchmarks that would trigger actions to mitigate environmental impacts, nor do they commit ARB to taking action in the event that significant, unanticipated environmental impacts occur.

In sum, absent specific performance standards, timely and rigorous monitoring of all relevant information, and particularized commitments to respond in specified ways to triggering events, the “adaptive management” approach described by ARB will not prevent significant environmental effects, and will not permit ARB to respond to unanticipated effects in a timely or effective manner. As a result, ARB’s proposed adaptive management approach to mitigation violates CEQA. The rule, as proposed in the proposed modifications, also represents a failure to comply with Board direction. In their resolution accompanying the approval of the Cap and Trade Regulation in December 2010, the Board directed the Executive Officer to: “Determine whether there are feasible alternatives or mitigation measures that could be implemented to reduce or eliminate any potential adverse environmental impacts…” and to adopt “any modifications that are necessary to ensure that all feasible mitigation measures or feasible alternatives that would substantially reduce any significant adverse environmental impacts have been incorporated into the final action…” The additional reporting requirements in the 15-Day changes for the Mandatory Reporting Rule require the collection of basic information about the mass of forest biomass material and the harvest permit under which it was collected. However, with respect to environmental impacts to forests, this falls far short of satisfying the above directives by the Board or establishing specific performance standards. (CBD4)

Response: See response to CBD1 regarding the proposed adaptive management approach and why it does not constitute “deferred mitigation.”

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CBD5

Name: Brian Nowicki and Kevin Bundy
Affiliation: Center for Biological Diversity
Written Testimony: 9/27/2011
Second 15-Day Comment #: 2093

Comment: The proposed modifications eliminate section 95852.2(a)(4)(c), which had required that wood and wood waste materials to be combusted as biomass fuel "not transport or cause the transport of species known to harbor insect or disease nests outside zones of infestation…" (Page A-103.) The notice offers this explanation: "Section 95852.2(a)(4)(C) was removed in response to comments received from stakeholders who claimed that tracking and enforcement of sources of wood and wood wastes is extremely difficult for energy generators." However, there is a high probability that commercial timber land owners—who may not be able to harvest trees killed by bark beetles and disease for lumber or other durable wood products—would welcome the opportunity to sell those trees to biomass energy generators. To the extent that it makes harvest and transportation of these trees economical, the biomass fuel market is likely to become a significant driver of the harvest of trees killed by insects and disease. The elimination of this requirement openly invites the transport of infected and infested materials. This creates a substantial threat to California's forest resources and represents bad public policy. Purchasers of biomass fuels in large quantities—such as owners and operators of biomass power plants can be expected for sound business reasons to enter into contracts with fuel suppliers such as large timber corporations and the United States Forest Service. Those contracts easily could specify that the operators will not accept fuels if doing so would require the transport of infested and diseased materials. Relieving a few "stakeholders" of this purported burden cannot outweigh ARB's responsibility, as an agency required to uphold the public trust, to ensure that its actions do not threaten California's forests as a whole by exposing them to transportation of insects and disease. (CBD5)

Response: The commenter indicates that the removal of Section 95852.2(a)(4)(C) would invite transport of infected and infested materials, thereby possibly resulting in a new environmental impact. ARB disagrees. The California Department of Forestry has oversight of the harvesting of wood and wood wastes, and is required to identify species known to harbor insect or disease nests and approve transportation.
PRC, Ch.10, Article 5, is dedicated to Forest Insect and Plant Disease Control. State laws authorizing the control of forest pests, including Sections 4712-4718, 4799.08-4799.12, and the Federal Forest Pest Control Act (Public Law 110), allows broad administrative discretion in the use of public funds to detect and control forest pests on lands of all ownerships.

PRC Section 4715 allows the Department of Forestry and Fire Protection, in accordance with policy established by the Board of Forestry, to enter into agreements with any owner and with any agency of government, including the federal government, for the purpose of controlling or eradicating forest insects or plant diseases damaging or threatening destruction to timber or forest growth, and it may make expenditures for that purpose.

> PRC Section 4716 grants the following authority to the Director of the Department of Forestry and Fire Protection.
>
> > (a) Whenever the director determines that there exists an area that is infested or infected with insect pests or plant diseases injurious to timber or forest growth and that the infestation or infection is of such a character as to be a menace to the timber or timberlands of adjacent owners, the director, with the approval of the board [Board of Forestry], may declare the existence of a zone of infestation or infection, and describe and fix its boundaries.
> >
> > (b) If the director declares the existence of a zone of infestation or infection pursuant to subdivision (a), the department or its agents may go upon state and private lands within the zone of infestation or infection and shall cause the infestation or infection to be eradicated or controlled in a manner that is approved by the board.

Further, Forest Practice Rules 917.9, 937.9, 957.9, 957.10, 957.11. “Prevention Practices” contain guidelines that address the buildup of destructive insect populations or the spread of disease, hazard reduction and treatment alternatives.

Notwithstanding the protection of regulatory restrictions on the potential transport of invested plant or woody materials, the economics of biomass power plants would preclude transport of materials far from the plant or woody fuel source. Fuel costs are critical to the economic viability of biomass power plants and transportation costs can be the largest component of the cost of fuel. As a result, the “fuel shed” of a biomass power plant must be a limited distance from the plant. Prior environmental investigations have found that within 50 miles, the transport of biomass fuel can still be viable and beyond that distance, the transport begins to be economically infeasible. Therefore, if any material were to carry an infestation, the environmental effect would be minimized by the economic limitations of the cost of fuel transport. Once at the plant, the fuel would be combusted and the risk of spreading an infestation would be eliminated. Recognizing the regulatory protections and the limited distance of fuel transport, any potential for environmental effects from infested plant or woody materials would be less than significant.

CBE1

Name: Adrienne Bloch
Affiliation: Communities for a Better Environment
Written Testimony: 12/14/2010
45-Day Comment #: 762

Comment: Large California NOx, CO, and other co-pollutant reductions can be achieved if an alternative is adopted requiring direct control measures using methods known by CARB (e.g. for boilers and heaters). These co-pollutants otherwise cause large cumulative impacts in impacted communities. Similarly, CARB should evaluate other co-pollutants including PM2.5 and toxics which feasible direct controls would achieve. AB 32 requires addressing the co-pollutants issues, but the proposed cap-and-trade regulation and Scoping Plan do not. (CBE1)

> **Response:** In developing the Scoping Plan in 2008, the Staff Report for the Cap-and-Trade Regulation, and again in the *Supplement to the AB 32 Scoping Plan Functional Equivalent Document* (Supplement), which was presented at the August 2011 Board meeting, we evaluated the air quality impacts of a direct regulation compared to a cap-and-trade program. The proposed Cap-and-Trade Regulation is designed to reduce GHG emissions and is not directly applicable to other pollutants. However, criteria pollutants and toxic air contaminants are generally expected to decline as a result of GHG reduction measures. Consequently, the proposed Cap-and-Trade Regulation would not contribute to a cumulative increase in co-pollutants. FED page 343.
>
> The proposed Cap-and-Trade Regulation has the distinct advantage of imposing an enforceable cap on emissions—making it the most likely method to successfully meet the AB 32 goal of capping emissions at 1990 levels by 2020. As described on page IV-3 of the proposed Cap-and-Trade Regulation Staff Report, direct regulations for emission sources do not provide the same assurance of reductions as those offered by a cap-and-trade program.
>
> The proposed Cap-and-Trade Regulation and the source specific alternative share challenges. If a cap-and-trade program is not adopted, ARB would instead have to adopt numerous source-specific regulations on many different types of sources. Before ARB adopts a regulation on a source category, staff must spend considerable time investigating the category to determine what level of emissions control is cost effective and technologically feasible. Some sectors may not be regulated at all because, after investigation, staff determines that emission standards are not cost-effective or technologically feasible, or that the potential emission reductions are so small that regulation is not justified.
>
> In addition, it takes considerable time to develop each individual regulation. This means that some sources will be regulated first; others will be regulated later—perhaps much later if the category presents difficult technical issues.

Even if regulations are ultimately determined to be feasible and are adopted, the delay in adoption, and the potentially long lead times necessary for some sources where feasibility is an issue would mean that emission reductions at certain sources will likely occur much later than at other sources. It is, therefore, very difficult to predict at this time (i.e., before staff has done the necessary technical work) both where emission reductions will occur and when they will occur. Some sources or source categories near environmental justice communities may remain unregulated, or may achieve emission reductions much later than if the source had instead been regulated under the cap-and-trade program.

Another reason why uncertainty is a characteristic of regulatory systems relying on source-specific regulations is that each source-specific regulation can be designed in different ways. Different levels of emission controls can be specified, and source-specific regulations often have exemptions for certain types of sources that cannot comply with a specified standard. Many regulations also have compliance flexibility features that allow such options as the use of averaging or even the use of offsets to meet some compliance obligations. Because of these exemptions or compliance flexibility features, there is no guarantee that uniform reductions at each individual source will occur. Different impacts to neighboring communities could, therefore, result from the Regulation, as compared to a regulation without such flexibility.

Exemptions or compliance flexibility that may be included in any source-specific regulation may be superficially appealing but present serious downsides. One reason that exemptions may be included in a source-specific regulation is that not all individual sources can achieve the same level of emission reductions due to various factors such as the source's age or use of particular types of equipment. If a standard is set that all facilities can meet (e.g., in order to satisfy the requirements of technological feasibility and cost-effectiveness set forth in AB 32) the emission standards may have to be set much less stringently in order to meet these requirements. If carefully targeted exemptions or less stringent standards are instead allowed for certain types of facilities, the standards on the remaining sources may be able to be set much more stringently. Such a regulatory structure may be necessary in order to achieve the maximum feasible emission reductions (another requirement of AB 32) from the source category as a whole. The same rationale may also justify the inclusion of flexibility options in a source-specific regulation.

Comment: A highly preferable alternative proposal would have been a thorough evaluation of Reasonably Available Control Measures necessary to meet CARB's requirements under AB 32 for maximum reductions, to reduce smog in non-attainment zones, and toxics in overburdened heavily industrial areas. The following sections identify specific sources that should have been considered. For example, additional reductions could be achieved from:

(1) Requiring In-State reductions from industrial boilers and heaters, which CARB has already identified.

(2) Removing industrial exemptions for methane from smog regulations.

(3) Requiring implementation of specific refinery by refinery measures identified in the industrial energy efficiency audits.

(4) Limiting emissions and conversion to processing Heavier Crude at oil refineries (which is not cancelled out by adding polluting ethanol to gasoline).

(5) Requiring oil refineries to switch fossil fuel electricity use to clean alternative energy sources (since oil refineries use significant electricity). (CBE1)

Response: See the response to CRPE1 regarding the reasonable range of alternatives considered in the FED. See response to comment CBE1 regarding consideration of source-specific reduction alternative, above. The commenter offers a range of source-specific GHG reduction measures that could be implemented by ARB. These measures have been considered in the context of evaluating the Additional Source-Specific Command-and-Control Regulations Alternative (see page 387-390 of the FED).

ARB examined a reasonable range of alternatives as required under CEQA. The array of source-specific measures recommended in the comment presents a scenario of additional regulatory actions. ARB staff believes that most of the measures suggested by the commenter are not feasible and the remaining measures, while they have some reduction potential, may be substantially inflated relative to what a regulatory approach might actually cost-effectively achieve.

ARB has adopted an energy efficiency and co-benefits audit regulation. The audit results from this regulation are due at the end of 2011. ARB staff has committed to evaluate opportunities to achieve facility-specific cost-effective emission reduction opportunities that will result in GHG and co-pollutant benefits and require these reductions under a regulatory program. Staff does not believe that mandated improvements of this type are administratively feasible under a regulation at this time due to the lack of data on specific reductions that can be achieved.

Comment: Boiler and Heater NOx and CO Co-pollutant emissions are large and if directly controlled would yield large local health benefits. AB 32 requires ARB to design the program to prevent any increase in emissions of toxic air contaminants or criteria pollutants. It also requires it to consider the overall societal benefits of reducing other air pollutants and benefits to the environment and public health. Yet the draft regulation demonstrates that reductions could have been achieved to substantially reduce co-pollutant emissions but was rejected.

CARB provided two spreadsheets calculating available measures for reducing CO_2 emissions from industrial boilers and heaters, which are major pollution sources. Measures include replacing old boilers of low or medium efficiency, optimizing combustion, improving insulation maintenance, etc. (listed below and in the attached spreadsheets). CARB identified how much energy would be saved for each of these measures in MMBTU (million British Thermal Units). CARB provided these reduction opportunity calculations not because these are being directly mandated, but to show possible ways that industrial sources could reduce, but are nevertheless allowed to buy their way out of under Cap and Trade. There was no showing that these reductions would not have been cost-effective. Regardless, the CARB list underscores the availability of measures for direct control. If these controls were implemented locally instead of traded, they would not only result in the CO_2 emissions reductions identified by CARB, but would also result in very substantial co-pollutant reductions. CARB should have considered such an alternative project to address co-pollutant impacts.

It is a simple matter to calculate the co-pollutants associated with the energy savings identified in the boiler and heater spreadsheets. For example, standard AP42 emission factors for NOx and CO are available, based on natural gas combustion. This will generally underestimate emissions because more polluting fuels are often used by these boilers and heaters, but applying the natural gas factors provides a conservative estimation, and still comes out to large emissions. The result, in tons per day, is provided below. The detailed tables are attached as an appendix. The full spreadsheets are separately attached. (CBE1)

> **Response:** See response to CRPE1 regarding the reasonable range of alternatives considered in the FED. See response to CBE1 regarding consideration of source-specific reduction alternative.
>
> The commenter suggests that a greater reduction of co-pollutant emissions could be achieved through the direct regulatory control of boiler and heater emissions. ARB examined a reasonable range of alternatives as required under CEQA, including the adoption of direct regulatory controls. While direct regulation offers some reduction potential, the estimated reductions presented by the commenter may be substantially inflated relative to what a rule approach might achieve. The commenter draws on material prepared by ARB staff for the proposed cap-and-trade rulemaking (Appendix F) and contends that the conceptual emission reductions that might be obtained with these measures could be required as a direct regulation. Staff is currently evaluating how facility-specific cost-effective emission reduction opportunities identified by energy efficiency and co-benefits audits due by the end of 2011 could be required under a regulatory program. The commenter is assuming the results of a broad analysis or audits are applicable over a diverse set of sources requiring widespread efficiency

improvements. Staff does not believe that mandated improvements of this type are administratively feasible under a regulation at this time. The commenter also rightfully notes the uncertainty in estimates of emission reductions possible from these types of measures due to potential overlapping of estimated reduction opportunities (such as replacing or improving boilers).

Further, although boiler and heater source-specific reduction measures could achieve substantial GHG reductions, for the reasons described in response CBE1 above, both a source-specific regulatory program and a cap-and-trade program can have a similar result in the real world, but it depends on the many details of how the regulations are designed. The FED indicates that at this time ARB cannot predict in which sectors and what geographic locations the emission reductions would occur under the source-specific alternative. However, it does indicate that emission limits applied to specific regulated entities and facilities could provide more certainty regarding the location of GHG emission reductions, which could be an environmental advantage of this alternative. In comparing the Additional Source-Specific Command-and-Control Regulations Alternative with the Cap-and Trade program, ARB determined that the source-specific alternative (see page 395 of the FED) would result in the low likelihood or no likelihood of achieving the project objectives for five objectives (i.e., equitable distribution, cost-effectiveness, minimize leakage, establish a declining cap, and linkage with partners), whereas the proposed Cap-and-Trade Regulation would have a high likelihood for achieving all objectives. For these reasons, and for other supporting economic and feasibility reasons included in the Initial Statement of Reasons, ARB has rejected this alternative as not being environmentally superior to the proposed action.

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CBE4

Name: Greg Karras
Affiliation: Communities for a Better Environment
Written Testimony: 8/11/2011
First 15-Day Changes Comment #: 1166

Comment: Some of the amendments to the proposed Regulation would cause more severe and significant environmental effects than those disclosed by the draft FED, and warrant revision of the FED. ARB failed to revise and recirculate the environmental document to disclose the impacts of the amendments. Given the likely significant environmental impacts from the substantial changes to the proposed Regulation, ARB should revise and recirculate the FED before adopting any amendments to the proposed Cap and Trade Regulation.

CEQA requires that the agency prepare a response to comments before adopting a final EIR or FED. This final action is due in October 2011. Yet, at the same time, the Board has directed the Executive Officer to report back to the Board in July 2011 on the "finalization of the allowance allocation system", "implementation of a market tracking system", "implementation of an auction system", and "implementation of an offset tracking system." At the same time comments are being taken, and before the final FED is prepared, ARB will be actively preparing markets for Cap and Trade. As such, the Board has adopted a Cap and Trade Regulation before completing CEQA.

The process is further aggravated because the Board in its December resolution also directed the Executive Officer to "modify" several aspects of the Regulation, and never mentioned considering the environmental consequences of the changes. The Board has not considered CEQA or environmental consequences at all in deciding whether or not to approve this project. The Executive Officer alone will review the FED comments, which are based on the pre-amendment regulations. The Executive Officer should at least have the benefit of comments on the completed draft EIR, one that reflects the true project and its impacts.

During the comment period for the Scoping Plan alternatives, ARB also released amendments to the Cap and Trade Regulation for public comment. ARB's decision to create an overlapping comment process also undermines public participation and ARB's ability to genuinely consider the project's significant impacts. It is not possible to fully comment on both documents at once. ARB's insistence on thrusting this Regulation forward without ensuring that it will avoid significant impacts casts serious doubt on the process as a whole and CARB's willingness to hear from all but a select few "stakeholders" whose opinions are solicited. (CBE4)

> **Response:** The commenter expresses an opinion that the Board has adopted the Cap-and-Trade Regulation before completing CEQA, that the Board has not considered CEQA or the environmental consequences of the proposed 15-Day changes, and that ARB's decision to create an overlapping comment process undermines public participation. The commenter suggests that the FED should

be revised and recirculated before adopting any amendments to the proposed Cap-and-Trade Regulation.

The commenter suggests that ARB has not considered the environmental effects of the proposed changes directed by the Board in its December 2010 resolution. This is not correct. Following a public hearing held on December 16, 2010, the Board adopted Resolution 10-42, which directed staff to make a number of modifications to the proposed Regulation. On July 25, 2011, the first Notice of Public Availability of Modified Text and Availability of Additional Documents (First 15-Day Change Notice) was issued. The public comment period for the First 15-Day Change Notice ended on August 11, 2011. On September 12, 2011, additional modifications to the regulatory text were proposed in a Second Notice of Public Availability of Modified Text and Additional Documents and Information (Second 15-Day Change Notice).

The commenter offers no evidence to support the contention that the analysis in the FED warrants revision and recirculation. ARB staff reviewed the 15-Day changes and determined that the changes would not result in new impacts or change the level of significance of already identified impacts, and therefore does not require revision or recirculation of the FED. (See also response to CPRE4.)

ARB concurrently complies with APA and CEQA requirements through its CRP. ARB typically has multiple regulatory proposals underway on parallel time frames and complies with the environmental review requirements for all of them. ARB has complied with the requirements of its CRP for the preparation and circulation of the FED and preparation of these written responses to comments.

With regard to adoption of the proposed Cap-and-Trade Regulation, ARB disagrees with the commenter. The Board has not taken final action to adopt the proposed Regulation prior to completion of the environmental process. The Board is scheduled to consider the responses to comments on the FED at the October 20, 2011 hearing prior to taking final action on the Regulation.

Comment: ARB's revisions to tables 8-1 and 9-1 of sections 95870 and 95891 would cause more severe and significant environmental effects than those disclosed by the draft FED. These changes revise the timing and amount of refinery emissions which ARB proposes to "allocate" for free (proposes not to control) in ARB's proposed equation given in section 95891. As ARB's own AB 32 program documentation acknowledges, oil refineries are the largest industrial emitter in its program. (CBE4)

Response: As noted by the commenter, the 15-Day changes provide additional detail on industry benchmarking and allowance allocations. The modifications are consistent with anticipated and ongoing refinement of the proposed Regulation and do not substantially alter the magnitude of potential environmental impacts or the suggested level of significance presented in the Draft FED. Benchmarking is a process to estimate representative emission factors by sector, and provide a baseline for allowance allocation. The referenced 15-Day changes simply incorporate benchmark values that were not available when the Draft FED was prepared. The provision of free allowances is proposed to minimize potential leakage in exposed sectors, and was addressed in the Draft FED on pages 9 and 40:

> "Staff proposes to create a gradual transition into the program through the design of the allocation system. ARB will rely primarily on free allocation at the start of the program to minimize near-term costs to California consumers and businesses and to minimize emissions leakage. The allocation design will reward those who have invested in energy efficiency and GHG emission reductions and will encourage continued investment in clean and efficient technologies in the future."

A common misconception is that the provision of free allowances discourages a covered entity from implementing measures to reduce emissions. In fact, the provision of free allocations does not result in fewer improvements being implemented by covered facilities. Although an entity could simply return allowances at the close of a compliance period, if the value of the allowances exceeds the cost of improvements, free allowances provide opportunities for entities to implement compliance actions at reduced cost.

Comment: ARB added section 95852(a)(2) to the proposed cap and trade regulation. This new section appears to exempt oil refineries from including the major greenhouse gas emissions from combustion of fuels, including natural gas liquids. Natural gas can be stored as liquid natural gas, which is later burned as natural gas. This exemption would cause significant air pollution impacts and exacerbate pollution hotspots by taking one of the largest sources of combustion emissions at refineries completely out of any compliance requirement.

Response: The proposed change does not exempt these fuels from regulatory compliance. In 2015, the compliance requirement for these fuels simply changes from the facility combusting the fuel to the facility/operator providing the fuel. Refineries both provide the fuel and combust the fuel, and as such would continue to be responsible for compliance after 2015.

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CIPA

Name: Norman Plotkin
Affiliation: California Independent Petroleum Association
Written Testimony: 8/11/2011
First 15-Day Changes Comment #: 1134

Comment: In currently pending litigation, a California State trial court found that the analysis of the alternatives identified in the FED was not sufficient for informed decision-making and public review under CEQA. Under the abuse of discretion review taking place, a Supplement was prepared to provide an expanded analysis of the five project alternatives discussed in Section V of the 2008 Scoping Plan FED. Based on Alternative 5 of the Supplement, CARB has met all of the objectives and the emissions targets of AB 32. One need only eliminate Cap and Trade from that mix because the emissions reduction yield from Cap and Trade was always a "plug" number. It was a number to plug in to get to the evolving target, a catch all buffer in case actual reductions didn't materialize as projected. Cap and Trade's inclusion was a sop to business and lip service to those who believe that credit trading was the foundation for a "green economy." More importantly, a Combined Strategies alternative that does not include Cap and Trade also does not constitute a No Project designation, which is a political non-starter. (CIPA)

> **Response:** The commenter urges ARB to consider Alternative 5 from the Scoping Plan FED Supplement (which was a combination of strategies including a cap-and-trade program), but eliminate the Cap-and-Trade Regulation to reduce emissions and meet AB 32 goals. No specific comments on the adequacy of the environmental analysis prepared for the Cap-and-Trade Regulation were raised. The commenter is referred to the response below, and no further response is required.

Comment: The largest single impediment to the rational policy decision to jettison Cap and Trade and instead rely on the established mix of combined strategies and measures is CARB's desire to construct the mix of measures in such a fashion that the target reductions are skewed higher than necessary to meet AB 32 goals because of a desire to put California on a path to meet the long-term 2050 goal of reducing California's GHG emissions to 80 percent below 1990 levels because CARB believes this trajectory is consistent with the reductions that are needed globally to help stabilize the climate. CIPA argues that this scale is unachievable at the state level and that this policy horizon is too long for rational development of midterm solutions and is in practical effect the enemy of the good. (CIPA)

> **Response:** The commenter urges ARB to consider eliminating the Cap-and-Trade Regulation and instead consider a mix of measures to reduce emissions and meet AB 32 goals and expresses the opinion that some of the reduction levels are overstated, because of ARB's perceived desire to attain 2050 goals, rather than just 2020 goals. No specific comments on the adequacy

of the environmental analysis were raised; therefore, no further response is required.

If approved, the Cap-and-Trade Regulation would be a single regulation in a suite of GHG reduction measures implemented by ARB to reduce GHG emissions. The list of Ongoing, Approved and Foreseeable Measures is available on the ARB website at:

http://www.arb.ca.gov/cc/inventory/data/tables/reductions_from_scoping_plan_measures_2010-10-28.pdf

These measures alone do not achieve the reductions necessary to reach the AB 32 target in 2020. If the Cap-and-Trade Regulation is approved, it would achieve the additional reductions necessary to reach the target. Further, ARB is continuing to evaluate additional regulatory measures that could be implemented to reduce emissions from specific sources. Most additional measures have not reached a level of development that they can be counted towards achieving the 2020 target with a reasonable level of confidence.

Comment: In CIPA comments on the Supplement to the AB 32 Scoping Plan Functional Equivalent Document, dated July 28, 2011, we noted that the FED Supplement fails to provide an accurate baseline because the GHG reductions attributable to other programs are underestimated or omitted and the effects of the economic recession on statewide GHG emissions have been underestimated. Specifically, we argued that the FED Supplement does not include the GHG reductions associated with two measures that CARB has already adopted or is adopting, namely the Commercial Recycling Measure and the Energy Efficiency And Co-Benefits Assessment. Moreover, we pointed out that the FED Supplement does not include any of the GHG reduction programs that CARB has proposed but not yet adopted. CARB has estimated that the GHG reductions attributable to those measures total 68 MMT exceeding the 22 MMT shortfall. Yet, CARB provides no analysis in the FED Supplement as to the foreseeability of these measures or the likely effect those measures will have on achieving the AB 32 target.

Insofar as the FED Supplement ignores GHG reduction programs implemented or under development by the federal government and other state agencies such as the California Public Utilities Commission, we noted that the baseline has been skewed. Even though CARB states in the FED Supplement that it has updated the environmental baseline to account for events subsequent to the original FED prepared for the Proposed Project, CARB has not included these programs in its updated baseline. As a result, CARB's updated baseline is inflated and overstates any shortfall in achieving the AB 32 target. Indeed, proper accounting for these omitted programs could exceed the 22 MMT shortfall estimated in the Supplemental FED. Although the FED Supplement states that it has updated the environmental baseline by accounting for the effects of the recent economic recession on statewide GHG emissions, there is no explanation, let alone any quantitative analysis, as to how CARB accounted for those recessionary effects. Indeed, the only information provided in the FED Supplement on this issue is a conclusory statement that CARB relied on the energy demand forecast provided in the

2009 “IEPR” prepared by the California Energy Commission (CEC). Yet, in findings issued in March 2011 – before the publication of the FED Supplement – the CEC acknowledged that its 2009 forecast substantially under predicted the depth and duration of the recession. Accordingly, CARB’s baseline of GHG emissions is significantly overstated. CIPA asserts, again, that CARB has met all of the AB 32 objectives and the emissions targets through Alternative 5 of the Supplement- Variation of the Combined Strategies or Measures. One need only eliminate Cap and Trade from that mix to arrive at a Combined Strategies Alternative that satisfies AB 32. (CIPA)

> **Response:** The commenter urges ARB again to consider Alternative 5 of the Supplement to the Scoping Plan FED with elimination of the Cap-and-Trade Regulation. The commenter did not submit specific comments on the environmental analysis conducted for the Cap-and-Trade Regulation in the FED, therefore, no further response is required.

Comment: Do not be afraid to accept that CARB has met all of the AB 32 objectives and the emissions targets through Alternative 5 of the Supplement- Variation of the Combined Strategies or Measures. One need only eliminate cap and trade from that mix to arrive at a Combined Strategies Alternative that satisfies AB 32 and avoids the pitfalls that await an ill-defined market plan and does not suffer the credibility gap of a take no action alternative. We urge you to embrace adaptation as a policy response, fully count the Combined Measures and Strategies taken to date and jettison the dangerous California only Cap and Trade rule. (CIPA)

> **Response:** Refer to response to preceding CIPA comment.

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CRPE1

Name, Affiliation: Sofia Parino, Center on Race, Poverty and the Environment; Tom Frantz, Association of Irritated Residents; Penny Newman, The Center for Community Action and Environmental Justice; Teresa DeAnda, El Comite para el Bienestar de Earlimart; Martha Guzman Aceves, California Rural Legal Assistance Foundation; Anna Yun Lee, Communities for a Better Environment; Jane Williams, California Communities Against Toxics; Nicole Capretz, Environmental Health Coalition
Written Testimony: 12/14/2010
45-Day Comment #: 693

Comment: The Board should not adopt the proposed cap and trade rule. ARB has not conducted a proper foundational analysis to justify this choice of a market mechanism, and ARB has not analyzed a reasonable range of alternatives in accordance with the California Environmental Quality Act ("CEQA"). (CRPE1)

> **Response:** The commenter asserts that ARB has not analyzed a reasonable range of alternatives in accordance with CEQA, but provides no specificity. It is not possible to respond to this general comment, other than to reiterate that the FED complies with all applicable CEQA requirements, including analysis of alternatives.
>
> ARB held a Scoping Meeting for the Cap-and-Trade FED on August 23, 2010 to solicit public input on environmental impacts and the range of project alternatives to be evaluated. The FED considered five alternatives to the project. See Chapter 6.0, "Alternatives Analysis," of the FED, including a range of market and non-market approaches to GHG reduction. Alternatives consisted of five different cap-and-trade program designs, carbon fee, direct regulation approach, and the no-project alternative. This represents the spectrum of GHG reduction strategies used by states, provinces, and nations. In accordance with the substantive requirements of CEQA, the alternatives analyzed in the FED represent a "reasonable range" that could potentially feasibly attain most of the basic project objectives while having the potential to reduce or eliminate significant environmental effects. Generally, a range of alternatives analyzed in an environmental document is governed by the "rule of reason," requiring evaluation of those alternatives "necessary to permit a reasoned choice" (See Title 14 CCR section 15126[f]). The initial screening of potential alternatives had to at least potentially meet the objectives, and alternatives were included only after consideration of their potential feasibility based on technical, legal, and regulatory grounds. The five alternatives covered a range of policy level alternatives sufficient to permit a reasoned choice.

Comment: ARB'S analysis of alternatives to the proposed Regulation violates the California Environmental Quality Act. AB 32 requires "the state board to adopt greenhouse gas emission limits and emission reduction measures by regulation," which triggers the CEQA requirement for an Environmental Impact Report (EIR). As a certified regulatory program, ARB discussed possible impacts in the form of a Functional Equivalent Document (FED) in lieu of an Environmental Impact Report, pursuant to Public Resources Code section 21080.5.

ARB failed to adequately analyze project alternatives in the Functional Equivalent Document. Under CEQA, ARB must examine a reasonable range of alternatives to the proposed project that feasibly meet most of the project's basic objectives while avoiding or substantially reducing the significant effects of the project. The selection of alternatives should foster informed decision making and public participation. CEQA also makes clear that the purpose of the alternatives analysis is to focus on alternatives that are capable of "avoiding or significantly lessening any significant effects of the project, even if those alternatives would impede to some degree the attainment of the project objectives, or would be more costly." In evaluating alternatives, ARB must include "sufficient information about each alternative to allow meaningful evaluation, analysis and comparison with the proposed project."

For purposes of developing and evaluating the proposed project and alternatives, ARB derived the following objectives from AB 32:

- Achieve technologically feasible and cost-effective aggregate reductions;
- Distribute allowances equitably;
- Avoid disproportionate impacts;
- Credit early action;
- Complement existing air standards;
- Be cost-effective;
- Consider a wide range of public benefits;
- Minimize administrative burden;
- Minimize leakage;
- Weigh relative emissions;
- Achieve real emission reductions;
- Achieve reductions over existing regulation;
- Complement direct measures;
- Consider emissions impacts;
- Prevent increases in other emissions;
- Maximize co-benefits;
- Avoid duplication;
- Establish declining cap;
- Reduce fossil fuel use;
- Link with partners;
- Design enforceable, amendable program; and
- Ensure emissions reductions.

Having articulated these objectives (notably, without regard to their accuracy, and to the statutory requirements in AB 32), ARB then presented a cursory, circular and results-oriented description of five alternatives to the proposed plan. The five alternatives ARB identified were:

(1) No project. This Alternative comprises the bulk of the alternatives analysis. The section generally describes sector by sector the business as usual impacts compared to the proposed Cap-and-Trade Regulation;

(2) Implement only additional source-specific command-and-control regulations. This alternative purports to consider implementation of source-specific emission limits by regulation. However, in its Executive Summary, ARB demonstrates its preference for cap and trade above all other forms of controls with an unsubstantiated conclusion that direct regulations cannot provide the same assurances for reductions that a cap and trade program because of an uncertainty in emissions reductions caused by the diverse nature of many industrial processes and a lack of data. This conclusion is not only nonsensical to justify the inclusion of these same diverse and data-poor industrial processes in a cap and trade program (under which all reductions must be real, permanent, quantifiable, verifiable, and enforceable) but is unsubstantiated, based only on the excuse that ARB does not have the data to properly regulate these industries. In its analysis, ARB acknowledges that command-and-control regulations “can take several forms.”

    However, instead of performing a meaningful analysis of any of the forms possible, ARB “assumed that only regulated emission limits would be implemented” on sources (as opposed to technology). As such, ARB failed to identify and analyze the specific command-and-control regulations which would be appropriate here. Instead ARB summarily states that the specifics necessary to conduct such analyses “would depend on the information that is learned in the future during the regulatory development process.” And yet, prior to initiating any “regulatory development process,” ARB identifies five objectives with which source-specific emission limits would not be likely to achieve in Table 6-1 on “Comparative Likelihood That Alternatives Achieve Project Objectives.”

    Table 6-1 ranks on a scale of high, medium, and low the likelihood that each alterative considered would be likely to achieve each of the 22 objectives ARB identified. Here, each of the “no or low likelihood to achieve objective” ratings received by the source-specific command-and-control regulation alternative pertained to objectives that were either not applicable to source-specific command-and-control regulations or not analyzed. First, stated objective two is to distribute allowances equitably. Under a source-specific emissions limit program there are no allowances to distribute and thus the objective is inapplicable here. However, the underlying intent of the specified objective appears is to ensure equitable treatment of entities. In this case that purpose is served in that there is an equitable distribution of zero allowances. Stated objective five is to complement existing air standards. While Table 6-1 rates source-specific emissions limits as low here, nowhere else in the FED is the issue addressed. In fact, the brief program description on page 388 discusses how this alternative would “likely focus primarily on the industrial sector because the transportation, electricity and natural gas sectors are already extensively addressed." Given this cursory analysis, it appears that source-specific regulations would in fact be designed to complement existing air standards.

Stated objective nine is to "minimize leakage." However, in the objectives section ARB specifically notes that "command-and-control regulations can be designed to minimize or avoid leakage." No further explanation as to how leakage is caused, or could be minimize under this alternative, other than to say that administrative burdens may increase, is provided. Stated objective 18 is to establish a declining cap. This objective is either inapplicable, as source-specific emission limits envision no cap to begin with, or it is fulfilled by analogy. The intent of the objective is to "cover 85 percent of the state's GHG emissions in furtherance of California's mandate to reduce GHG emissions to 1990 levels by 2020." Since there is no "cap" in source-specific regulations, the objective of a "declining cap" is not applicable. However, the intent of the objective is to continually lower emission levels and this intent could be fulfilled through a source specific regulatory scheme. In fact, the U.S. EPA regularly writes mobile source emission regulations (source- specific command-and-control regulations) that increase in stringency over time.

Lastly, stated objective 20 is to link with other Western Climate Initiative (WCI) partners to create a regional market system. While Table 6-1 concludes there is no or a low likelihood of achieving this objective, there is no elucidating discussion as to why it is not possible. Generally, command-and-control regulations do not envision a market system; however, no aspect of such a program precludes regulatory schemes from linking together partners in some way. In failing to fully envision, consider, and describe how source-specific emission limits could operate in California, ARB has not included sufficient information on source-specific emission limits "to allow meaningful evaluation, analysis and comparison with the proposed project." ARB preemptively rejects this alternative as "challenging," but acknowledges that "the certainty about avoiding localized increases in emissions could be an environmental advantage of this alternative." This is a key advantage for environmental justice communities, and does not allow ARB to so quickly dismiss it in favor of a cap and trade program;

(3) Carbon fee. ARB describes implementation of a carbon fee as similar to cap and trade in that both programs place a price on GHG emissions, which thereby provides an incentive for businesses and individuals to reduce their emissions. Similarities between the two programs include "reporting, monitoring, verification of covered entities' GHG emissions." ARB states that the main difference between the programs is that implementing a carbon fee "provides price certainty for the covered entities" but lacks emission certainty. ARB's analysis of a carbon fee is fundamentally flawed in again failing to envision and analyze how the program would actually work. Thus, it fails to meet CEQA's requirement for "sufficient information about each alternative to allow meaningful evaluation, analysis and comparison with the proposed project." Instead of developing a real alternative, ARB focuses on

elements of the proposed cap and trade program which have already been developed and then unfairly compares the developed proposal with the mere title “carbon fee” absent a more developed program which would allow for a more reasoned analysis. For example, ARB acknowledges that the efficiency of a carbon fee could be enhanced by pairing it with “complementary approaches, such as performance standards,” yet it “assume[s] that only a carbon fee would be implemented.” Also, ARB states that to avoid passing costs on to consumers, a system of offsets could be used, but it fails to consider the alternative with such a system and instead criticizes a carbon fee as passing costs onto consumers. Additionally, ARB finds that the potential for leakage is increased with a carbon fee as opposed to a cap and trade system, but fails to consider how to tailor fee levels to market influences, while at the same time stating that it can be done. In ARB’s “Comparative Likelihood That Alternatives Achieve Project Objectives,” Table 6-1, four objectives are identified as having a “no or low likelihood to achieve objective.”

Stated objective six, to be cost-effective, is identified as not likely to be achieved. Nowhere in ARB’s discussion of a carbon fee is cost effectiveness directly discussed. In fact, ARB notes so many potential similarities between cap and trade and a carbon fee, without mention of the apparent cost ineffectiveness associated with a carbon fee that one can only speculate as to how cap and trade has a high likelihood of cost effectiveness while a carbon fee has a low likelihood of cost effectiveness. ARB ranks implementation of a carbon fee as unlikely to minimize leakage, in stated objective nine. However, ARB’s incomplete analysis failed to consider a carbon fee program that provides opportunities to tailor the fee level to market influences, while at the same time acknowledging that such mechanisms are possible and that they could decrease the potential for leakage. Without conducting an analysis that fully considers what the likely implementation of a carbon fee program would include, ARB’s conclusion is preemptive and arbitrary.

ARB’s stated objective 18 is to establish a declining cap. This objective is either inapplicable, as this implementation of a carbon fee envisions no cap to begin with, or it is fulfilled by analogy. The intent of the objective is to “cover 85 percent of the state’s GHG emissions in furtherance of California’s mandate to reduce GHG emissions to 1990 levels by 2020.” Since there is no “cap” in this vision of a carbon fee, the objective of a “declining cap” is not applicable. However, the intent of the objective is to continually lower emission levels and this intent could be fulfilled through increasing the carbon fee.

Lastly, stated objective 20 is to link with other WCI partners to create a regional market system. While Table 6-1 concludes there to be no or a low likelihood of achieving this objective, there is no elucidating discussion as to why is it not possible for WCI partners to also adopt a carbon fee. In failing to fully envision, consider, and describe how a carbon fee could operate in California, ARB has failed to provide sufficient information allow a meaningful evaluation of a carbon fee;

(4) California cap and trade program linked with a Federal cap and trade program. ARB discusses the possibility of linking the proposed California cap and trade program to a Federal cap and trade program in the alternatives analysis sections of both the Initial Statement of Reasons and the Functional Equivalent Document. However, linking a California cap and trade program to a non-existent Federal program is not an alternative at all. In fact, it is not an alternative for two reasons. First, an alternative must be an alternative to the proposed program. Here, the proposed program is cap and trade. The alternative discussed is the exact same cap and trade program but with a Federal partner. Ergo cap and trade is not an alternative program to cap and trade, regardless of what partnerships are formed.

Secondly, an alternative that has "no prospect in the near term," contains no detail whatsoever, has envisioned no mechanisms for implementation, enforcement, etc., is not a reasonable alternative. Thus, any linkage between a California cap and trade program and a Federal cap and trade program ought to have been discussed as an alternative cap and trade design feature and not under the guise of a legitimate cap and trade program alternative; and

(5) Alternatives to specific cap and trade program design features. ARB discusses five design features possibly applicable to the proposed cap and trade program. Conspicuously absent from the alternatives analysis is an alternative that geographically limits offsets. (CRPE1)

Response: See response to CRPE1 regarding the reasonable range of alternatives considered in the FED. The FED evaluated a range of market and non-market approaches to GHG reduction. Alternatives consisted of five different cap-and-trade program designs, carbon fee, direct regulation approach, and the no-project alternative. This represents the spectrum of GHG reduction strategies used by states, provinces, and nations.

With regard to comments on the Additional Source-Specific Command-and-Control Regulation Alternative, the commenter disagrees with the conclusions and reasoning presented in the FED, and suggests that additional detail and rationale is required to describe why certain conclusions presented in Table 6-1 were drawn by ARB. The FED provides on pages 387 to 390 a balanced and adequate discussion of the source-specific, direct regulation approach to reducing GHG emissions. It addresses cost, effectiveness, leakage, and local impact issues, and recognizes that it could have some environmental advantage of avoiding any lingering uncertainty about potential for emissions to increase locally. It describes potential environmental impacts being generally similar to the Cap-and-Trade Regulation because the compliance responses would be comparable (i.e., primarily onsite emissions reductions actions). See also CBE1 response. The potential disadvantages of high compliance costs (because of the lack of a market approach that can find the most cost-effective strategies) and the potential for leakage are noted. The additional detail sought by the commenter is not necessary for an informed consideration of the source-specific, command-and-control approach.

The commenter expresses concern about the ranking of the source-specific, command-and-control approach as not likely to fulfill the objective of linking with other WCI-partner programs. It is important to note that the primary reason for linkage would be to provide for connection of market-based approaches to broaden opportunities for emissions reductions, trading of allowances, or development of offset projects. The direct regulation approach, like the source-specific, command-and-control regulation, is not facilitated by linking with other jurisdictions, which is why its ranking for this objective was low likelihood in Table 6-1.

The commenter criticizes the analysis of the carbon fee alternative and recommends consideration of several variations of the design of a carbon fee program. The FED sought to define a reasonable carbon fee strategy, which is discussed on pages 390 to 393 of the document. Certainly, a wide range of potential design features and concepts could be considered within a carbon fee program. It is not necessary or feasible to evaluate many design variations of a carbon fee strategy to understand its environmental impacts. Because it assigns a price to carbon, the compliance responses and, therefore, the environmental impacts of a carbon fee approach would be similar to cap-and-trade, as noted on page 392 of the FED. The potential for differences is also discussed, in terms of the achievement of project objectives and certain possibilities for environmental effects.

Related to achievement of project objectives, the commenter criticizes the rankings in Table 6-1 for several alternatives and declares that some low likelihood rankings should be “inapplicable” instead (i.e., not ranked for that objective). This change would disguise a potential shortcoming of an alternative. The table compares how well each objective is achieved. If an objective is considered inapplicable for an alternative, it is not fulfilling that objective, and the table shows it as a low likelihood of achieving that objective. Also, the substantiation of the rankings is based on information in the descriptions of alternatives and subsections specifically devoted to consideration of objectives (see subsection a under the Impact Discussion of each alternative). Consequently, the analysis of the carbon fee alternative is adequate for purposes of CEQA.

The commenter indicates that linkage with a Federal program should not have been dismissed from more detailed evaluation. ARB disagrees, recognizing that there is no Federal program, nor the prospect of one because of the lack of Congressional action at this time. Therefore, it would be too speculative to attempt to predict the character and content of a Federal program. Consequently, it is appropriate to not discuss it in further detail.

Finally, the commenter noted that a cap-and-trade design option of geographic limits for offset projects should have been considered. No other detail is provided regarding the commenter's goal for including such a design variation. The success of offsets depends, in part, on allowing for the market sufficient capacity to respond to the opportunity to develop offset projects and offer credits. Constraining the market geographically would also limit market opportunities, so it could hinder an offset program's effectiveness. Because it is not clear what perceived environmental advantage the commenter is seeking to derive from geographic limits, no further response can be provided.

Comment: ARB failed to adequately analyze a range of project alternatives in the Functional Equivalent Document. ARB did not satisfy the CEQA requirement to examine a reasonable range of alternatives. Under CEQA, ARB must examine a reasonable range of alternatives to the proposed project that feasibly meet most of the project's basic objectives while avoiding or substantially reducing the significant effects of the project. CEQA does not supply the number of alternatives that are necessary for a meaningful analysis to take place, but it makes clear that a rule of reason governs requiring the EIR document to set forth "those alternatives necessary to permit a reasoned choice." In the ISOR, ARB purports to analyze four alternatives. In reality, only two alternatives are presented. The "no project" alternative is not a real option in this case given the statutory obligation provided in AB 32. Second, linking a California cap and trade program to a non-existent Federal cap and trade program is not a reasonable alternative for the reasons stated above (see section IV.A.). Lastly, presenting program design features which do not alter the program itself is not a project alternative. For these reasons, a mere two alternatives were considered in the FED. Given the size and implication of a statewide cap and trade program, as well as the broad range of possible avenues to attain the achievement of AB 32, the rule of reason dictates that a reasonable range of alternatives exceed two. Therefore, ARB has failed to satisfy CEQA's requirement to examine a range of reasonable alternatives to the project. (CRPE1)

Response: ARB disagrees with the commenter's assertion that it did not evaluate a reasonable range of alternatives in the FED. The alternatives presented in the FED were selected to evaluate a range of plausible actions that could achieve project objectives. The basis for the selection of the FED's alternatives included:

- A no project alternative is standard in ARB alternatives analyses, and is called for by the CEQA guidelines,
- Consideration of other ways to achieve project objectives is a sound basis for formulation of alternatives, e.g. cap-and-dividend, cap-and-fee, or carbon fee,
- Consideration of public and stakeholder input. ARB held a scoping meeting for the FED (August 23, 2010) for this purpose,
- Alternatives based on ARB's experience and research, and,

- Direct regulations and a carbon fee are the most often cited alternatives to the proposed Cap-and-Trade Regulation, so they were evaluated as alternatives in the FED.

The commenter offers no evidence why the alternatives analysis provided in the FED is not adequate, therefore, no further response is necessary.

Comment: The analysis of offsets produced by manure digesters violates CEQA. The FED finds no impact on air quality and no cumulative impact on air quality from implementation of the Compliance Offset Protocol for Manure Digesters. The FED concedes that engines combusting digester gas emit criteria and toxic emissions. However, the FED assumes that all offset generating projects would be subject to Clean Air Act requirements and local land use decisions that would fully mitigate the criteria and toxic emissions. The FED fails to demonstrate that to be the case, or to require air pollution controls as a condition of receiving offsets. For the same reason, the FED has failed to adequately analyze the emissions of criteria and toxic air pollutants from offsets produced at dairy digesters when there is no reasonable basis to conclude that all such projects would be reduced to a less than significant level (there is no substantial evidence supporting this assumption). (CRPE1)

Response: The commenter states that the FED failed to demonstrate that air quality impacts of offset generating projects would be fully mitigated to a less-than-significant level. The commenter mistakenly states that the FED assumes that all digester facilities would not be subject to Clean Air Act (CAA) requirements. In fact, the Livestock Offset Protocol specifically describes that in order for a livestock digester project to qualify for the offset, it must be implemented in accordance, as required by law, with all applicable federal, state, and local regulations and regulatory oversight requirements. The FED identified (see page 240) that these regulations included federal, state, and local construction and operational air quality permits; CAA and the California CAA; local land use entitlements including environmental (CEQA/NEPA) review; and dust abatement plans for facilities located in PM nonattainment areas. Where a facility would result in a net increase in criteria pollutant (or precursor) emissions in an extreme nonattainment area, it would not be permitted by the local air district. Based on all of these requirements, ARB concluded that the Livestock Offset Protocol would not conflict with adopted air quality plans, violate Ambient Air Quality Standards, and/or result in cumulatively significant increases in criteria pollutants. The commenter offers no other evidence to dispute this conclusion; therefore, no further response is necessary.

Comment: Conclusion. For the reasons set forth above, the Board should not adopt the proposed cap and trade regulation. Instead, the undersigned organizations are asking the Board to consider the impact of the Superior Court's ruling in the pending Scoping Plan challenge, to prepare a proper foundational analysis for whether cap and trade is the maximum feasible and cost-effective reduction, to adopt more appropriate direct regulations and market-based compliance mechanisms than a cap and trade rule, and meaningfully analyze a reasonable range of alternatives in accordance with CEQA.

The Board should seize this opportunity to set California on a path that protects vulnerable communities, fosters green jobs, and stimulates a path to a green economy for California. (CRPE1)

> **Response:** This comment summarizes the commenter's previous comments. See previous responses to CRPE comments.

CRPE4

Name, Affiliation: Sofia Parino, Center on Race, Poverty & the Environment; Maria Covarrubias, Comité ROSAS; Domitila Lemus, Comité Unido de Plainview; Maria Buenrostro, Comité Luchando por Frutas y Aire Limpio; Penny Newman, The Center for Community Action and Environmental Justice; Linda Mackay, TriCounty Watchdogs; Jesse Marquez, Coalition for a Safe Environment; Angela Meszros; Strela Cervas, California Environmental Justice Alliance; Tom Frantz, Association of Irritated Residents; Salvador Partida, Committee for a Better Arvin; Ruth Martinez, Comité Si Se Puede; Ana Ceballor, La Voz de Toniville; Teresa DeAnda, El Comité Para El Bienestar de Earlimart; Gary Lasky, Sierra Club Tehipite Chapter; Shabaka Heru, Society for Positive Action; Caroline Farrell
Written Testimony: 8/11/2011
First 15-Day Comment #: 1110

Comment: The modified Cap and Trade Regulation released on July 7, 2011 is different enough from the version that the Functional Equivalent Document was based upon that it must be recirculated and go through another EIR process before it can be approved in accordance with CEQA. CEQA does not allow the Board to delegate the review of an EIR to the Executive Officer. Because of the failure to complete environmental review before approving the project as well as the substantial modifications to the rule that require recirculation, the full Board must complete the legally-required environmental review process before approving this rule. (CRPE4)

Response: ARB disagrees that the FED must be revised and recirculated. Although the regulation has been amended in several respects, the cap on emissions has remained the same and the method of allocation of allowances has not appreciably changed. ARB staff reviewed 15-Day changes to the regulation language and determined that the proposed changes would not result in new impacts or substantially change the type or significance of impacts disclosed in the FED. Therefore, no revisions were required to the FED. No significant new information was added to the FED and the FED was not changed in a way that deprives the public of a meaningful opportunity to comment upon a substantial adverse environmental effect of the project, or a feasible way to mitigate or avoid such an effect. The public was provided opportunity to comment on the environmental analysis during the initial 45-day public comment period, as well as two subsequent 15-Day comment periods associated with proposed revisions of the Regulation language. Therefore, the requirements that would trigger revision or recirculation of the FED did not occur.

ARB also disagrees that it approved the project in advance of the 15-Day changes or prior to completion of the environmental process. The Board has not taken final action to adopt the proposed Regulation. The Board is scheduled to consider for approval the written responses to comments on the FED at the October 20, 2011 hearing prior to taking final action on the Regulation.

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DWR

Name: Veronica Hicks
Affiliation: California Department of Water Resources
Written Testimony: 12/15/2010
45-Day Comment #: 728

Comment: The environmental impacts of imposing a surrender obligation on DWR were not evaluated. If DWR is required to surrender compliance instruments, it will need to pass these costs on to its water contractors, who in turn will pass the costs on to the end-users of water. An analysis should be conducted to determine the environmental impacts of this regulation. Water is integral to the agricultural sector and important for environmental needs. As reported in the California Water Plan, Update 2009:

> "California is facing one of the most significant water crises in its history- one that is hitting hard because it has many aspects and consequences. Reduced water supplies and a growing population are worsening the effects of a multi-year drought. Climate change is reducing our snowpack storage and increasing the frequency and intensity of floods. Court decisions and new regulations have resulted in the reduction of water deliveries from the Delta by about 20 to 30 percent. Key fish species continue to decline. In some areas of the state, our ecosystems and quality of underground and surface waters are unhealthy. The current global financial crisis will make it even more difficult to invest in solutions. We must act now to provide integrated, reliable, sustainable, and secure water resources and management systems for our health, economy, and ecosystems".

The regulation imposes an additional burden on DWR and California's water users without acknowledging this water crisis or evaluating the impact of this burden under all existing circumstances. (DWR)

Response: The commenter states that the FED does not evaluate the environmental effects of imposing a surrender obligation on DWR and suggests that the additional costs associated with a surrender obligation would result in environmental impacts that were not evaluated in the FED; however, the commenter is not specific as to what those impacts may be.

CEQA does not require discussion of economic changes unless the economic change would result in a physical effect on the environment (see CCR section 15064[e]). The commenter does not provide specifics as to how the economic impacts of the proposed Regulation would cause adverse physical environmental effects. Therefore, it is not possible to meaningfully respond to this general comment, other than to state that we believe the FED adequately evaluates the environmental effects of the proposed project in programmatic analysis in accordance with its CRP.

Higher prices would be expected to increase water conservation and improve the efficiency of water use, which could be considered beneficial effects. Non-CEQA aspects of this comment are addressed in the FSOR prepared in accordance with APA requirements.

DWR2

Name: Veronica Hicks
Affiliation: Department of Water Resources
Written Testimony: 8/11/2011
First 15-Day Changes Comment #: 1107

Comment: Did CARB conduct any analysis on the impact of the Regulation on different classes of water users (e.g. urban, agricultural, and environmental)? (DWR2)

> **Response:** The FED provides the environmental analysis of impacts related to compliance responses of covered entities. ARB considered the potential impacts of the proposed Regulation.
>
> Water users would not be subject to the proposed Cap-and-Trade Regulation except to that water purveyors that generate electricity, such as DWR, would be subject to the electrical generation sections of the proposed Regulation. The proposed the Cap-and-Trade Regulation would not regulate the availability, distribution, or use of water. Any impacts to water users that might occur would be the result of secondary price changes associated with electrical generation. A detailed environmental analysis of potential impacts to water users is not necessary under CEQA.
>
> A substantial proportion of the energy consumed in California is used for conveyance and treatment of water, and energy use represents the primary nexus between the proposed Cap-and-Trade Regulation and water. Energy providers (electricity generation and fuel providers) that would be subject to the Cap-and-Trade Regulation may pass increased costs to customers, including customers that use energy to convey and treat water. The proposed market-based program would allow covered entities to seek the least expensive manner of compliance and thus minimize costs. Further, increased costs may result in more efficient use of water. The FED appropriately provides a programmatic level environmental analysis. No direct adverse environmental impacts to water users are expected to result from this activity. The evaluation of indirect environmental impacts that might affect individual classes of water users (most of whom are not regulated entities) resulting from economic changes and the presumed actions of individual water purveyors is beyond the scope of a programmatic analysis and are too speculative to evaluate in the FED.

Comment: Did CARB conduct an analysis identifying the economic and environmental impacts of this regulation, specifically based on impacts to water uses? More specifically, did CARB analyze the impacts on agricultural water users, who may have a disproportionately high level of water use compared to their electricity use? (DWR2)

> **Response:** The commenter questions whether the FED evaluates the economic and environmental effects of the Regulation on water users. Refer to the

response to the preceding comment. Non-CEQA aspects of this comment are addressed in the FSOR prepared in accordance with APA requirements.

Comment: Did CARB consider the economic and environmental impacts such as land use changes and crop-shifting that could result from this regulation's possibly larger impact on agriculture, particularly in light of the assertion by federal power providers that they are not obligated to comply with this regulation, and the resulting incentives which would encourage additional water use on lands entitled to receive federal water deliveries? (DWR2)

Response: Agriculture activities are not directly regulated under the Cap-and-Trade Regulation. Potential indirect impacts to agriculture would be economic, consisting of secondary price changes. CEQA does not require discussion of economic changes unless the economic change would result in a physical effect on the environment (see CCR section 15064[e]). The expected outcome of possible incremental increases in the price of water would be increased water conservation and more efficient use of water, which could be considered beneficial effects. Further environmental analysis is not necessary.

Federal water is allocated based on water rights and not price. The proposed regulation would not change water rights nor would it alter the price of water provided by federal agencies.

ARB prepared the Updated Economic Evaluation of California's Climate Change Scoping Plan, which includes a cap-and-trade program. That evaluation used the ENERGY 2020 model to assess the potential changes in energy use, both type and volume, brought on by the proposed Cap-and-Trade Regulation. The model did not indicate that the use of biomass would increase in response to the proposed Cap-and-Trade Regulation, and consequently crop switching to increase the production of fuel crops or other changes in land use would not be expected. Table 27 of the report demonstrates that potential economic impacts to agriculture from AB 32 climate policies would be comparable to those in other sectors of the economy. Consequently, a detailed analysis of potential economic impacts to agriculture is not warranted. The FED appropriately provides a programmatic level environmental analysis.

DWR3

Name: Veronica Hicks
Affiliation: Department of Water Resources
Written Testimony: 9/27/2011
Second 15-Day Changes Comment #: 2064

Comment: DWR references comments from their earlier comment letters, and asserts that the environmental and economic impacts on DWR and water users have not been addressed.

Response: Refer to responses to DWR and DWR2.

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FRIENDSOFEARTH2

Name, Affiliation: Kate Horner, Friends of the Earth US; Rolf Skar, Greenpeace; Victor Menotti, International Forum on Globalization; Bill Barclay, Rainforest Action Network
Written Testimony: 8/11/2011
15-Day Changes Comment #: 1175

Comment: It is inappropriate for the ARB to move ahead with amendments to, or approval of, these regulations. The ongoing litigation by environmental justice groups under the California Environmental Quality Act raises legitimate concerns regarding the harm of implementing a cap and trade program on California's environment and vulnerable, overburdened communities across the state. As noted by plaintiffs in the case and as we note below, the original regulation failed to meet the criteria set out by AB 32 for market-based compliance mechanisms, and the modifications do not cure these defects. In general, we find that the amendments offered as part of the 15-Day Rulemaking Package do not ensure either environmental or financial market integrity within the proposed cap and trade rules. The ARB should take this opportunity to perform a meaningful and comprehensive alternatives analysis rather than moving forward with the same program at issue in the litigation. (FRIENDSOFEARTH2)

Response: The commenter suggests that because of ongoing litigation on the Scoping Plan, it is inappropriate for ARB to proceed with consideration of the Cap-and Trade Regulation. The commenter further suggests that ARB should prepare a comprehensive alternatives analysis. The commenter references a lawsuit filed against ARB on the Scoping Plan FED. In response to that lawsuit, ARB prepared and circulated the Supplement to the AB 32 Scoping Plan FED (June 13, 2011), which was considered and approved by the Board prior to taking action to re-approve the Scoping Plan on August 24, 2011. The Scoping Plan is a valid approved plan, within which the proposed Cap-and-Trade Regulation is a recommended measure.

The 2008 Scoping Plan outlines the State's strategy to reduce GHG emissions to 1990 levels by 2020, as required by the Global Warming Solutions Act of 2006 (AB 32; Núñez, Chapter 488, Statutes of 2006). A "scoping plan" is required by one provision of AB 32 (Health and Safety Code (HSC) section 38561), and ARB's adoption of GHG reduction measures is authorized under a separate provision (HSC section 38562). It is not required that a particular measure be encompassed in a scoping plan in order for ARB to pursue such a measure as a proposed regulation.

In the Cap-and-Trade FED, ARB evaluated five alternatives to the Cap-and-Trade Regulation, including several iterations of the cap-and-trade program design. The alternatives analysis provides a comparative evaluation of environmental impacts of each alternative (see pp. 365 to 395 of the FED). ARB made a good faith effort to provide a comprehensive analysis of the comparative environmental effects and achievement of project objectives for each of the alternatives. No specific inadequacies of the alternatives analysis were provided by the commenter; therefore, no further response is necessary.

HDDP2

Name: Bradley K. Heisey
Affiliation: High Desert Power Project
Written Testimony: 12/14/2010
45-Day Comment #: 617

Comment: Based on the HDPP situation, ARB's CEQA review of the proposed Cap-and-Trade Regulation is deficient with respect to 2012 if ARB adopts it as proposed. ARB has not determined the economic or environmental effects of requiring "locked-in" generators like HDPP to purchase 100 percent of their GHG allowances through the proposed auctions at the outset of the program in 2012, with the resulting potential loss of relatively low emitting MWh of energy production in California and replacement by higher GHG emitting electrical generators from the outset of the cap-and-trade program in 2012. (HDPP2)

> **Response:** The commenter suggests that the economic and environmental impacts of requiring “locked-in” generators (i.e., locked into electricity rates by contract) to purchase allowances at auction was not analyzed in the FED.
>
> The first compliance period is now proposed to begin January 2013, a year later than originally proposed. If the Board approves, the Regulation this modification resolves the concern expressed by the commenter.
>
> With regard to environmental impacts, the commenter suggests that the Cap-and-Trade Regulation as proposed would force HDPP (a private utility) to shut down or limit operations in 2012. The concern appears to be the perception that HDPP would be economically penalized for having to purchase GHG allowances without being able to pass the costs of the allowances along to its customers because it is currently operating under a fixed price contract through December 2012 and cannot change the prices to reflect the increased costs of the GHG allowances. The commenter suggests, although the reasoning behind the suggestion is not clear, that higher GHG-emitting electrical generators would replace the lower GHG-emitting electrical generation provided by HDPP in the event of such a shutdown.
>
> The FED provides a comprehensive environmental analysis of the proposed Cap-and-Trade Regulation, including the potential for leakage of emissions outside of California as a result of the cost of allowances and the environmental effects of potential offsets, which are intended to help reduce allowance prices. It is too speculative to suggest that significant or substantially greater environmental impacts would occur as a result of an individual locked-in generator not being able to pass along the GHG allowance costs to their customers. There are many economic, regulatory, and environmental factors to consider. It is not feasible to predict the possibility of closing a power plant (versus other potential compliance responses) because of the cost of allowances. Further, even if electrical generation by lower GHG-emitting

generators would cease or be replaced by higher-emitting GHG generators for 2012, implementation of the overall cap-and-trade program over its 20-year time horizon would result in substantially less GHG emissions compared to baseline conditions, because the declining cap controls overall emissions. This was described as an environmental benefit on page 105 of the FED.

NCPA3

Name: Susie Berlin
Affiliation; McCarthy & Berlin, P.C. for Northern California Power Agency
Written Testimony: 8/11/2011
First 15-Day Changes Comment #: 1176

Comment: NCPA urges CARB to work with local air quality districts as those agencies undertake CEQA reviews of proposed geothermal projects to ensure that the local air districts apply the same metrics for evaluating a project's impact as CARB does when measuring that impact for compliance with the Cap and Trade Regulation. All of the State's environmental objectives are best served by a uniform and comprehensive approach to the treatment of GHG emissions from geothermal facilities. (NCPA3)

> **Response:** ARB concurs that the State's environmental objectives are best served by a uniform and comprehensive approach to the treatment of GHG emissions, including those from geothermal facilities. ARB will continue to work with the local air districts. Local air districts have discretionary authority in preparation of their environmental analyses and determination of significance of impacts, including GHG impacts.

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NRDC4

Name: Alex Jackson
Affiliation: Natural Resources Defense Council
Written Comment: 12/16/2010
45-Day Comment #: 958

Comment: NRDC believes that the FED is a careful and thorough review of the potential environmental impacts of the cap and trade regulation, in particular in its choice of alternatives to examine. We are also pleased that ARB chose to include adaptive management not as mitigation but rather as part of the program design with respect to forest offset projects and local air quality impacts (FED at 45-47). This use of adaptive management adds legitimacy to the FED in these two areas that have been the subject of much public comment and concern. Moreover, to its credit, ARB is not attempting to take credit for adaptive management as mitigation for recognized, potential negative impacts to air quality or forestry practices. (NRDC4)

> **Response:** This comment supports the alternative analysis and the adaptive management approach. No further response is necessary.

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PCAPCD2

Name: Thomas Christofk
Affiliation: Placer County Air Pollution Control District
Written Testimony: 8/11/2011
15-Day Comment #: 1051

Comment: CEQA should be explicitly distinguished within the regulation because it is not a law that in and of itself imposes reductions requirements. Public Resources Code section 21004 states that "a public agency may exercise only those requirements or implied powers provided by law other than [CEQA]." We recommend that the regulation recognize that offset credits used by a facility for the compliance obligation under the CARB Cap and Trade Regulation should be a part of any CEQA analysis that may be required for that same facility. Offset credits should be taken into account either early on within the setting of the baseline for a project, or as mitigation. The recognition of the purchase of offset credits within the CEQA process is not 'double dipping' because CEQA only requires that a project discloses its impacts. It does not independently provide the legal authority to impose any legal obligation. (PCAPCD2)

> **Response:** The commenter recommends that the regulation recognize that offset credits used by a facility should be part of any CEQA analysis required for that facility, and that offset credits should be identified in the setting of a CEQA document as an existing condition, or as mitigation in the impact analysis. This comment addresses the future treatment of offsets under local CEQA analyses, but does not challenge the adequacy of the environmental analysis prepared for the proposed Cap-and-Trade Regulation. Nonetheless, this document appeared to be a logical location to identify the comment and respond accordingly.
>
> The proposed Cap-and-Trade Regulation establishes criteria for GHG offsets to be used as a compliance mechanism in a market-based reduction program. Offset credits are included in the regulation essentially as cost-containment mechanisms. Under the proposed Cap-and-Trade Regulation, offsets do not mitigate for increased emissions, but rather provide an option to defer expensive onsite improvements during a specified reporting period for covered entities.
>
> The proposed Regulation does not provide for any other use of offset credits, supersede any other air quality regulation that might require GHG reductions, or alleviate the requirement for a lead agency to fully comply with CEQA. ARB rejects commenter's suggestion that the Regulation be amended to allow the use of offsets for CEQA mitigation purposes by lead agencies. Staff does not believe that ARB has the authority to make determinations regarding CEQA mitigation requirements for projects for which it is not the lead agency, e.g. projects that fall within the authority of local permitting authorities. Lead agencies are responsible for determining the baselines for GHG emissions for their respective projects that are subject to CEQA, and for determining the level of significance for impacts. The recognition of offsets in any capacity in a project-specific CEQA analysis is at the discretion of the lead agency and permitting authorities, notably local air

districts for CEQA air quality analyses. ARB staff is not aware of any existing mechanism in the CEQA statute or Guidelines that allows the purchase of an offset credit under the cap-and-trade program as mitigation for projects subject to CEQA.

The environmental impacts of <u>developing</u> a specific offset project consistent with a protocol may need to comply with CEQA. The protocol requires compliance with all other applicable federal and state laws and regulations. The environmental impacts of the offset protocols have been programmatically evaluated in the FED. For example, the Urban Forest Protocol identifies that facilities that pursue this offset could result in increased urban tree plantings the installation of which would result in environmental impacts (e.g., dusts, noise, etc.).

SACREB

Name: Karen Klinger
Affiliation: Sacramento Real Estate Broker
Written Testimony: 12/16/10
45-Day Review Comment #: 983

Comment: There has not been appropriate outreach to the public or full disclosure telling the people what AB 32 really is, what it is linked to, and how all of the other links will accumulatively impact us. Knowing these many links exist, were they included in the DEIR and FEID? (SACREB)

> **Response:** ARB conducted over 30 workshops and public meetings related to the Cap-and-Trade Regulation, including a Scoping Meeting for the FED, available at the following website:
>
> http://www.arb.ca.gov/cc/capandtrade/meetings/meetings.htm#archive.
>
> ARB provides an assortment of AB 32 and Climate Change fact sheets that can be downloaded from the ARB website, and has web pages that are developed for specific audiences such as, general public, small business, local government, students and teachers. The FED was noticed in a 45 day Notice of Proposed Regulatory Action posted on ARB's website, noticed and circulated through the State Clearinghouse for agency review and comment, and publicly noticed in major newspapers in northern and southern California.

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USFLAW

Name: Alice Kaswan
Affiliation: University of San Francisco School of Law
Written Testimony: 12/10/2010
45-Day Comment #: 486

Comment: Alternative Rejected by Staff – Implement Only Additional Source-Specific Command-and-Control Regulations. CARB staff rejected the alternative of replacing the cap-and-trade program with a direct regulatory program for industrial sources. The Staff Report presents a number of convincing arguments for why regulation should not replace a cap-and-trade program, but did not address the value of complementing the cap-and-trade program with limited and targeted regulatory efforts where appropriate. The Staff Report expresses concerns about the cost-effectiveness of regulation if applied to all industries. But if regulation were used to complement cap-and-trade only where appropriate, CARB could take cost-effectiveness into account in deciding whether to impose regulations. In determining cost-effectiveness, it is also important for CARB to consider not only the costs of regulation to the relevant industry, but also the economic benefits of enhanced emissions reductions.

The Staff Report also observes that regulations would be difficult to draft given the lack of data on effective emission reduction mechanisms and the variation among facilities. However, CARB is requiring energy audits at industrial facilities, a process that includes an assessment of associated co-pollutant impacts. While current data may be insufficient, the audits could provide a much stronger basis for identifying cost-effective energy efficiency mechanisms that could be required at industrial facilities, and that could achieve both GHG and co-pollutant reductions.

CARB staff may be assuming that facilities will adopt cost-effective reduction strategies in response to the price signal created by the cap-and-trade program, without the need for command-and-control regulations. But industrial investment decisions are complex. Inertia, uncertainty about future carbon markets, concerns about short-term capital expenditures, and other factors could impede otherwise cost-effective investment in emission reductions. If price signals do not end up prompting cost-effective measures with significant co-pollutant benefits, then CARB should retain the authority to require appropriate measures.

In addition, if CARB identifies cost-effective GHG emission reduction measures with particularly significant co-pollutant benefits, then it would be consistent with AB 32's goals to require those measures rather than relying upon the vagaries of the market to incentivize them. Co-pollutant benefits could be particularly significant either because GHG reductions lead to a large reduction in associated co-pollutants, and/or because the industries to be regulated are located in especially polluted areas. (USF-LAW)

> **Response:** See response to CRPE1 regarding the reasonable range of alternatives considered in the FED and source-specific alternative response.

ARB believes that it has provided a reasonable range of alternatives for evaluation under the FED.

It is also important to note that ARB always retains the ability to pursue additional regulations. In fact, ARB is currently collecting information on opportunities for further GHG and co-pollutant emission reductions through the Energy Efficiency and Co-benefits Assessment Regulation for Large Stationary Sources. ARB is scheduled to receive these data by the end of 2011. Staff would then initiate a process to ensure that large industrial sources subject to the regulation be required to take all cost-effective and technically feasible actions identified under those audits. The audit results, due to ARB by the end of 2011, will inform the development of regulatory requirements staff intends to propose to the Board in 2012. Staff plans to initiate a separate public process in Fall 2011 to discuss metrics and actions to implement this commitment.

Also see the response to CBE1 regarding ARB's plans to implement an adaptive management plan.

Comment: In all provisions relating to the burning of biomass and biofuels, CARB should carefully assess associated co-pollutant and other environmental implications. For example, if biomass-derived fuel sources do not have to account for their GHG emissions, the rule could create incentives to use biomass that have incidental adverse environmental consequences. (USFLAW)

Response: The increased use of biomass is already incentivized by existing regulations such as the Renewables Portfolio Standards and the Low Carbon Fuel Standard. The Renewables Portfolio Standard (RPS) requires public owned utilities to obtain 33% of their energy from renewable resources. Most utilities are challenged to achieve the renewable target despite the availability of biomass as a renewable fuel.

ARB used the ENERGY 2020 model to assess the potential changes in energy use, both type and volume, brought on by the proposed Cap-and-Trade Regulation. The model did not indicate that the use of biomass would increase in response to the proposed Cap-and-Trade Regulation. Further, the proposed Cap-and-Trade Regulation would not supersede other air quality regulations. Combustion of biomass is subject to local permitting and emission control requirements.

ARB proposes to monitor the use of biomass as part of our monitoring and oversight of the implementation of the Cap-and-Trade Regulation.

VALERO2

Name: Matthew H. Hodges for Patrick Covert
Affiliation: Valero Companies
Written Testimony: 8/11/2011
First 15-Day Changes Comment #: 1062

Comment: It is presumptuous of CARB to continue development of a cap and trade regulation when the alternatives discussed in the Supplement to the AB 32 Scoping Plan Functional Equivalent Document (FED) have not been fully vetted. With the FED public comment period closing on July 28, 2011, CARB has not had sufficient time to consider all comments and respond appropriately. From a general perspective, the FED was a hastily prepared document lacking in critical details that draws upon a foregone conclusion that California must have a cap and trade regulation to meet the goals of AB 32. Resolution 10-42 (approved at a December 16, 2010 Board Hearing to consider adoption of the proposed Cap and Trade program), requires the Executive Officer to report on the progress being made on implementing the Cap and Trade program, provided the Cap and Trade program is approved. In the absence of a complete review of comments submitted in response to the FED and making a formal determination that other alternatives are not feasible or appropriate, it appears premature to continue the Cap and Trade rulemaking process. (VALERO2)

> **Response:** ARB prepared and circulated the Supplement to the AB 32 Scoping Plan FED (June 13, 2011). At a public hearing on August 24, 2011,the Board, after consideration of the alternatives analysis in the Supplement, public comment and staff's written responses to comments, voted to re-approve the Scoping Plan.

Comment: Valero strongly urges ARB to complete the regulatory development process prior to adoption, including full consideration of comments and alternatives presented in the FED, so that all impacts can be thoroughly reviewed as an entire package by the impacted parties. Valero believes that, if ARB presents a complete regulatory package, the impact to the economy, industry and consumers would be minimized. (VALERO2)

> **Response:** The commenter urges ARB to complete the regulatory process prior to adoption of the project, including full consideration of comments and alternatives presented in the FED. ARB has put forward a good-faith effort in preparing the FED for the Cap-and-Trade Regulation that was circulated for public review and comment, and staff has prepared written responses to comments on the FED in this document. The Board is scheduled to consider the FED, comments on the FED, staff's written responses to those comments, prior to taking final action on the proposed Regulation at a public hearing on October 20, 2011.

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EVALUATION OF REGULATORY (PROJECT) CHANGES

The Draft FED was included as Appendix O to the Staff Report prepared for the Regulation, and was circulated for public review and comment from October 28, 2010 to December 16, 2010. Since circulation of the FED, the Regulation language was modified, and two Notices of Public Availability of Modified Text and Availability of Additional Documents were issued.

The first 15-Day Change clarifies and revises the Regulation language to allow California's cap-and-trade program to better align with rulemaking efforts in other Western Climate Initiative (WCI) jurisdictions. These changes allow for future linkage that supports a broader, regional cap-and-trade program, provides more cost containment benefits to California-covered entities, and ensures greater reductions in regional emissions of greenhouse gases to the atmosphere. Staff also modified the Regulation language to begin the first compliance obligation in 2013. The allocation, auction, trading, and other activities will begin in 2012 before the start of the compliance obligation and the first compliance period. The 15-Day Change language provides that three-fourths of the "excess emissions" will be placed into the auction holding account, and not in the price containment reserve. Staff added flexibility to the statutes of limitations for invalidation of ARB offset credits, and added an equation to calculate how a compliance obligation would be assessed for electricity providers. The notice of the first 15-Day change can be found at:
http://www.arb.ca.gov/regact/2010/capandtrade10/2nd15daynotice.

The second 15-Day Change modifies or clarifies numerous sections of the Regulation, including those sections that apply to roles and responsibilities of covered entities, accounting and tracking, ensuring confidentiality and security of account representatives, and other key program design elements. The second notice can be found at: http://www.arb.ca.gov/regact/2010/capandtrade10/2nd15daynotice.pdf.

In addition, the general offset provision was modified to be more stringent, and the four Compliance Offset Protocols analyzed in the Draft FED were modified. These changes generally resulted in the protocols to be more environmentally protective. The Urban Forest Projects Protocol was modified to require an urban forester to be involved in the review of the project and offset project data report. The Livestock Projects protocol was modified to allow some mechanical flexibility, and thermo couplers for flares have been expanded to include engines, as well as adjustments to metered biogas flow data were replaced by a more conservative method to ensure rigorous accounting. The Ozone Depleting Substances Protocol was modified to include CFC-13 as an eligible gas into the methodology based on information from U.S. Environmental Protection Agency, and others. The U.S. Forest Project Protocol was modified to be more stringent by incorporating administrative, procedural, and legal provisions identified earlier in this document.

ARB staff reviewed the regulatory language modifications and evaluated whether they warranted any revisions to the environmental analysis in the FED, e.g. to reflect any new impacts or levels of significance of identified impacts. Staff has determined that the modifications consist largely of administrative and program design modifications that would not change the results or findings of the environmental analysis in the FED. Therefore, revision of the environmental analysis or recirculation the FED for further public review and comment is not required.

REFERENCES

California Air Resources Board. *Functional Equivalent Document prepared for the California Cap on GHG Emissions and Market-Based Compliance Mechanisms*. October 28, 2010. (Appendix O of the ARB Staff Report for the California Cap on GHG Emissions and Market-Based Compliance Mechanisms). http://www.arb.ca.gov/regact/2010/capandtrade10/capv5appo.pdf

California Air Resources Board. *Updated Economic Analysis of California's Climate Change Scoping Plan. Staff Report to the Air Resources Board.* March 24, 2010. http://www.arb.ca.gov/cc/scopingplan/economics-sp/updated-analysis/updated_sp_analysis.pdf

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ATTACHMENT B: CORRECTIONS FOR THE *STAFF REPORT: INITIAL STATEMENT OF REASONS* (ISOR), PART X

The California Air Resources Board identified several typographical errors and other minor problems in some of the references that were listed in the *Staff Report: Initial Statement of Reasons* (Staff Report) and associated appendices. For clarity, the following entries identify these errors and the necessary corrections.

STAFF REPORT: INITIAL STATEMENT OF REASONS (ISOR)

Page Numbers for Correction: II-33

The following reference contained a typo:

Original Text:
[24] *Renewable Electricity Standard*. California Air Resources Board. Found at: http://www.arb.ca.gov/energy/res/res.htm (accessed 10/10/10).

Replace With:
[24] *Renewable Electricity Standard:* (2010). California Air Resources Board. Found at: http://www.arb.ca.gov/energy/res/res.htm (accessed 10/10/10).

Page Numbers for Correction: II-55

The following reference was incomplete:

Original Text:
[31] http://www.arb.ca.gov/ch/programs/ej/ejpolicies.pdf

Replace With:
[31] California Air Resources Board: (2001). Policies and Actions for Environmental Justice. http://www.arb.ca.gov/ch/programs/ej/ejpolicies.pdf

Page Numbers for Correction: III-28

The following reference was incomplete:

Original Text:
[41] Good Practice Guidance for Land-Use, Land-Use Change and Forestry, (2003). Edited by Penman J., et al. Published by the Institute for Global Environmental Strategies (IGES) for the IPCC. Found at: http://www.ipcc-nggip.iges.or.jp/public/gpglulucf/gpglulucf_contents.html.

Replace With:
[41] Intergovernmental Panel on Climate Change (2003): Good Practice Guidance for Land Use, Land-Use Change and Forestry. Published by the Institute for Global Environmental Strategies (IGES) for the IPCC. http://www.ipcc-nggip.iges.or.jp/public/gpglulucf/gpglulucf_contents.html

Page Numbers for Correction: IV-5
The following reference was incomplete:

Original Text:
[49] HSC §38562 (b)(8).

Replace With:
[49] California Global Warming Solutions Act of 2006 (AB 32): (2006). Nunez, Statutes of 2006, Chapter 488. HSC §38562 (b)(8).

Page Numbers for Correction: VIII-5
The following reference was incomplete:

Original Text:
[90] The Energy 2020 Inputs and Assumptions book can be found at: http://www.arb.ca.gov/cc/scopingplan/economics-sp/models/book1002.pdf.

Replace With:
[90] The Energy 2020 Inputs and Assumptions book can be found at: http://www.arb.ca.gov/cc/scopingplan/economics-sp/models/book1002.pdf. In California Air Resources Board (2010): Modeling of Greenhouse Gas Reduction Measures to Support the Implementation of the California Global Warming Solutions Act (AB32).

Page Numbers for Correction: VIII-7
The following reference was incomplete:

Original Text:
[94] http://www.arb.ca.gov/cc/scopingplan/economics-sp/updated-analysis/updated_sp_analysis.pdf

Replace With:
[94] *Updated Economic Analysis of California's Climate Change Scoping Plan: Staff Report to the Air Resources Board.* March 24, 2010. http://www.arb.ca.gov/cc/scopingplan/economics-sp/updated-analysis/updated_sp_analysis.pdf (accessed September 23, 2010).

Page Numbers for Correction: VIII-7
The following reference was incomplete:

Original Text:
[95] http://www.arb.ca.gov/board/books/2010/042110/10-3-6-david-roland-holst-panelist.pdf

Replace With:
[95] Roland-Holst, David (2010): Roland-Holst Presentation: Climate Action for Sustained Growth: Analysis of ARB's Scoping Plan.
http://www.arb.ca.gov/board/books/2010/042110/10-3-6-david-roland-holst-panelist.pdf

Page Numbers for Correction: VIII-7
The following reference was incomplete:

Original Text:
[96] http://www.arb.ca.gov/cc/scopingplan/economics-sp/meetings/042110/bernstein.pdf

Replace With:
[96] Bernstein, Paul (2010): Presentation: Analysis of the California ARB's Scoping Plan and Related Policy Insights. Charles River Associates (CRA)
http://www.arb.ca.gov/cc/scopingplan/economics-sp/meetings/042110/bernstein.pdf

Page Numbers for Correction: References-12
The following reference was incomplete:

Original Text:
United States Energy Information Administration (1994): Quarterly Coal Report, January-April 1994. Washington, D.C.: DOE/EIA-0121(94/Q1)

Replace With:
Hong and Slatick (1994), "Carbon Dioxide Emission Factors for Coal," Quarterly Coal Report, January-April 1994, United States Energy Information Administration, Washington, D.C.: DOE/EIA-0121(94/Q1), pp. 1-8.

Page Numbers for Correction: References-14
The following reference was present in a footnote of Appendix F but not in the references list:

Add New Text:
U.S. Department of Energy (2005): ESA Conducted at Dairyman's Land O' Lakes Plant.

Page Numbers for Correction: References-15
The following reference was mistitled:

Original Text:
Western Climate Initiative (2010): Offset Criteria Draft Recommendations.
http://www.westernclimateinitiative.org/component/remository/Offsets-Committee-Documents/Offset-Criteria-Draft-Recommendations/

Replace With:
Western Climate Initiative (2010): Offsets System Essential Elements Draft Recommendations.
http://www.westernclimateinitiative.org/component/remository/Offsets-Committee-Documents/Offset-Criteria-Draft-Recommendations/

Page Numbers for Correction: References-15, References-63
Two WCI references were incorrectly presented:

Original Text:
Western Climate Initiative (2008): Design Recommendations for the WCI Regional Cap-and-Trade Program.
http://westernclimateinitiative.org/component/remository/general/program-design/Design-for-the-WCI-Regional-Program/
Western Climate Initiative (2010): Design for the WCI Regional Program.

Replace With:
Western Climate Initiative (2008, corrected 2009): Design Recommendations for the WCI Regional Cap-and-Trade Program.
http://www.westernclimateinitiative.org/document-archives/func-download/14/chk,911bb91d849f6096f55cb483cd7d8f57/no_html,1/

Western Climate Initiative (2010): Design for the WCI Regional Program.
http://westernclimateinitiative.org/component/remository/general/program-design/Design-for-the-WCI-Regional-Program/

Page Numbers for Correction: References-17
The following reference was incomplete:

Original Text:
Australian Government (2008): Australia Carbon Pollution Reduction Scheme White Paper. Department of Climate Change and Energy Efficiency.
http://www.climatechange.gov.au/publications/cprs/white-paper/~/media/publications/white-paper/V1006Chapter-pdf.ashx

Replace With:
Australian Government (2008): Carbon Pollution Reduction Scheme: Australia's Low Pollution Future. White Paper Volume 1. Department of Climate Change.
http://pandora.nla.gov.au/pan/102841/20090728-0000/www.climatechange.gov.au/whitepaper/report/index.html

Page Numbers for Correction: References-17
The following reference was incomplete:

Original Text:
Australian Government (2008): “Chapter 6: Coverage” in Carbon Pollution Reduction Scheme. Department of Climate Change and Energy Efficiency. http://www.climatechange.gov.au/publications/cprs/white-paper/~/media/publications/white-paper/V1006Chapter-pdf.ashx

Replace With:
Australian Government (2008): “Chapter 6: Coverage” in Carbon Pollution Reduction Scheme: Australia’s Low Pollution Future. White Paper Volume 1. Department of Climate Change http://www.climatechange.gov.au/publications/cprs/white-paper/~/media/publications/white-paper/V1006Chapter-pdf.ashx

Page Numbers for Correction: References-17
The following reference was incomplete:

Original Text:
Australian Government (2008): “Coverage of Synthetic Greenhouse Gas Emissions” in Carbon Pollution Reduction Scheme Green Paper. Department of Climate Change and Energy Efficiency http://www.climatechange.gov.au/~/media/publications/green-paper/greenpaper.ashx

Replace With:
Australian Government (2008): “Coverage of Synthetic Greenhouse Gas Emissions” in Carbon Pollution Reduction Scheme Green Paper. Department of Climate Change. http://www.climatechange.gov.au/~/media/publications/green-paper/greenpaper.ashx

Page Numbers for Correction: References-17
The following reference was incomplete:

Original Text:
Australian Government (2009): Obligation Transfer Number. Department of Climate Change and Energy Efficiency
http://www.aph.gov.au/senate/committee/climate_ctte/submissions/sub01.pdf
Berck et

Replace With:
Australian Government (2009): Carbon Pollution Reduction Scheme – Exposure Draft Legislation “Obligation Transfer Number”. Department of Climate Change. http://www.aph.gov.au/senate/committee/climate_ctte/submissions/sub01.pdf

Page Numbers for Correction: References-17
The following reference was incomplete:

Original Text:
Bernstein and Griffin (2005): Regional differences in the Price-Elasticity of Demand for Energy. http://www.climatechange.ca.gov/eaac/comments/2009-10-08_Sacramento_Municipal_Utilities_District-Attachment%202.pdf

Replace With:
Bernstein and Griffin (2005): Regional differences in the Price-Elasticity of Demand for Energy. RAND. http://www.climatechange.ca.gov/eaac/comments/2009-10-08_Sacramento_Municipal_Utilities_District-Attachment%202.pdf

Page Numbers for Correction: References-17
The following reference was incomplete:

Original Text:
Biotechnology Industry Organization (2009): Indirect Land Use Change, Low Carbon Fuel Standards, & Cap And Trade: The Role of Biofuels in Greenhouse Gas Regulation. http://bio.org/ind/climsustain/20090824.pdf

Replace With:
Biotechnology Industry Organization (2009): Indirect Land Use Change, Low Carbon Fuel Standards, & Cap And Trade: The Role of Biofuels in Greenhouse Gas Regulation. http://www.bio.org/sites/default/files/20090824_0.pdf

Page Numbers for Correction: References-18
The following reference was incomplete:

Original Text:
California Energy Commission (2009): 2009 Integrated Energy Policy Report. http://www.energy.ca.gov/2009publications/CEC-100-2009-003/CEC-100-2009-003-CMF.PDF

Replace With:
California Energy Commission (2009): 2009 Integrated Energy Policy Report, Final Commission Report, CEC-100-2009-003-CMF. http://www.energy.ca.gov/2009publications/CEC-100-2009-003/CEC-100-2009-003-CMF.PDF

Page Numbers for Correction: References-18
The following reference was incomplete:

Original Text:
California Energy Commission (2010): An Overview on Meeting California's Energy and Environmental Goals in the Electric Power Sector in 2020 and Beyond.
http://www.climatechange.ca.gov/energy/index.html

Replace With:
California Energy Commission (2010): California's Clean Energy Future An Overview on Meeting California's Energy and Environmental Goals in the Electric Power Sector in 2020 and Beyond. Report CEC-100-2010-002
http://www.cacleanenergyfuture.org/2821/282190a82f940.pdf

Page Numbers for Correction: References-19
The following reference is duplicative:

Delete Original Text:

California Energy Commission (2010): Report CEC-100-2010-002.
http://www.climatechange.ca.gov/energy/index.html

Page Numbers for Correction: References-19
The following reference was incomplete:

Original Text:
California Public Utilities Commission and California Air Resources Board (2010): Greenhouse Gas Calculator for the California Electricity Sector.
http://www.ethree.com/documents/GHG%203.11.10/GHG%20Calculator%20version%203b_Final_to_Post_March2010.zip

Replace With:
California Public Utilities Commission and California Air Resources Board (2010): Greenhouse Gas Calculator for the California Electricity Sector. Energy and Environmental Economics.
http://www.ethree.com/documents/GHG%203.11.10/GHG%20Calculator%20version%203b_Final_to_Post_March2010.zip

Page Numbers for Correction: References-19
The following reference was incomplete:

Original Text:
Charles River Associates (2010): Analysis of the California ARB's Scoping Plan and Related Policy Insights. http://www.arb.ca.gov/cc/scopingplan/economics-sp/meetings/042110/bernstein.pdf

Replace With:
Bernstein, Paul (2010): Presentation: Analysis of the California ARB's Scoping Plan and Related Policy Insights. Charles River Associates (CRA) http://www.arb.ca.gov/cc/scopingplan/economics-sp/meetings/042110/bernstein.pdf

Page Numbers for Correction: References-19
The following reference was incomplete:

Original Text:
Veritas (2010): Review of Existing Protocols against WCI Offset Criteria for the Western Climate Initiative. http://www.westernclimateinitiative.org/component/remository/Offsets-Committee-Documents/WCI-Review-of-Existing-Offset-Protocols

Replace With:
Det Norske Veritas (2010): Review of Existing Protocols against WCI Offset Criteria for the Western Climate Initiative.
http://www.westernclimateinitiative.org/component/remository/Offsets-Committee-Documents/WCI-Review-of-Existing-Offset-Protocols

Page Numbers for Correction: References-19
The following reference was incomplete:

Original Text:
Ecofys (2009): Sector Report for the Glass Industry. Fraunhofer Institute for Systems and Innovation Research, Oko-Institut.
http://ec.europa.eu/environment/climat/emission/pdf/bm/BM%20study%20-%20Glass.pdf

Replace With:
Ecofys (2009): Methodology for Free Allocation of Emission Allowances in EU ETS post 2012: Sector Report for the Glass Industry. Fraunhofer Institute for Systems and Innovation Research, Oko-Institut.
http://ec.europa.eu/clima/policies/ets/benchmarking/docs/bm_study-glass_en.pdf

Page Numbers for Correction: References-19
The following reference was incomplete:

Original Text:
Ecofys (2009): Sector Report for the Iron and Steel Industry. Fraunhofer Institute for Systems and Innovation Research, Oko-Institut.
http://ec.europa.eu/environment/climat/emission/pdf/bm/BM%20study%20-%20Iron%20and%20steel.pdf

Replace With:
Ecofys (2009): Methodology for Free Allocation of Emission Allowances in EU ETS post 2012: Sector Report for the Iron and Steel Industry. Fraunhofer Institute for Systems and Innovation Research, Oko-Institut.
http://ec.europa.eu/clima/policies/ets/benchmarking/docs/bm_study-iron_and_steel_en.pdf

Page Numbers for Correction: References-19
The following reference was incomplete:

Original Text:
Ecofys (2009): Sector Report for the Pulp and Paper Industry. Fraunhofer Institute for Systems and Innovation Research, Oko-Institut.
http://ec.europa.eu/environment/climat/emission/pdf/bm/BM%20study%20-%20Pulp%20and%20paper.pdf

Replace With:
Ecofys (2009): Methodology for Free Allocation of Emission Allowances in EU ETS post 2012: Sector Report for the Pulp and Paper Industry. Fraunhofer Institute for Systems and Innovation Research, Oko-Institut.
http://ec.europa.eu/clima/policies/ets/benchmarking/docs/bm_study-pulp_and_paper_en.pdf

Page Numbers for Correction: References-20
The following reference was incomplete:

Original Text:
Ecofys (2009): Sector Report for the Refinery Industry. Fraunhofer Institute for Systems and Innovation Research, Oko-Institut.
http://www.ecofys.nl/com/publications/documents/091102_Refineries.pdf

Replace With:
Ecofys (2009): Methodology for Free Allocation of Emission Allowances in EU ETS post 2012: Sector Report for the Refinery Industry. Fraunhofer Institute for Systems and

Innovation Research, Oko-Institut.
http://ec.europa.eu/clima/policies/ets/benchmarking/docs/bm_study-refineries_en.pdf

Page Numbers for Correction: References-20
The following reference was incomplete:

Original Text:
Food and Agriculture Organization (2005): Global Forest Resources Assessment.
http://foris.fao.org/static/data/fra2010/FRA2010_Report_1oct2010.pdf

Replace With:
Food and Agriculture Organization (2005): Global Forest Resources Assessment.
http://www.fao.org/forestry/fra/fra2005/en/

Page Numbers for Correction: References-20
The following reference was incomplete:

Original Text:
Galitsky et al. (2005): Energy Efficiency Improvement and Cost Saving Opportunities for the Pharmaceutical Industry. Lawrence Berkeley National Laboratory.
http://ies.lbl.gov/iespubs/energystar/glass.pdf

Replace With:
Galitsky et al. (2005): Energy Efficiency Improvement and Cost Saving Opportunities for the Glass Industry. An Energy Star Guide for Energy Plant Managers. Lawrence Berkeley National Laboratory. http://ies.lbl.gov/iespubs/energystar/glass.pdf

Page Numbers for Correction: References-20
The following reference was incomplete:

Original Text:
Gibbs, H. K. and J. O. Niles (2010). Preliminary Estimates of Forest Area and Forest Carbon Stocks in Developing Country GCF States and Provinces. Tropical Forest Group Report for the Governors' Climate and Forest Taskforce (GCF).

Replace With:
Gibbs, H. K. and J. O. Niles (2010). Preliminary Estimates of Forest Area and Forest Carbon Stocks in Developing Country GCF States and Provinces. Tropical Forest Group Report for the Governors' Climate and Forest Taskforce (GCF).
http://www.tropicalforestgroup.org/pdf/TFGIPCC2000GCFForestAreaCarbonDecember152010.pdf

Page Numbers for Correction: References-20
The following reference was incomplete:

Original Text:
Harvard-Duke Offsets Conference (2008): Carbon Offsets: Opportunities and Challenges for State Carbon Trading Schemes Panel 3.
http://www.law.harvard.edu/programs/about/elp/offsets-background-paper-2-final.pdf

Replace With:
Harvard-Duke Offsets Conference (2008): Carbon Offsets: Opportunities and Challenges for State Carbon Trading Schemes Panel 3 State of the States.
http://www.law.harvard.edu/programs/about/elp/offsets-background-paper-2-final.pdf

Page Numbers for Correction: References-20
The following reference was incomplete:

Original Text:
Haugen-Kozyra, Karen (2004): Alberta Agriculture, Food and Rural Development.
http://www.banffpork.ca/proc/2004pdf/p179-Haugen-Kozyra.pdf

Replace With:
Haugen-Kozyra, Karen (2004): Climate Change Policy, Markets and Greenhouse Gas Offset Trading. Alberta Agriculture, Food and Rural Development.
http://www.banffpork.ca/proc/2004pdf/p179-Haugen-Kozyra.pdf

Page Numbers for Correction: References-20
The following reference was incomplete:

Original Text:
Jaraite et al. (2009): Transaction Costs of Firms in the EU ETS. University College Dublin, School of Geography, Planning and Environmental Policy.
http://irserver.ucd.ie/dspace/bitstream/10197/2077/1/dimariac_confpap_014.pdf

Replace With:
Jaraite et al. (2009): Transaction Costs of Firms in the EU ETS. University College Dublin, School of Geography, Planning and Environmental Policy: Irish Economic Association.
http://irserver.ucd.ie/dspace/bitstream/10197/2077/1/dimariac_confpap_014.pdf

Page Numbers for Correction: References-20
The following reference was incomplete:

Original Text:
Jenkins, Olander, and Murray (2008): Addressing Leakage in a Greenhouse Gas Mitigation Offsets Program for Forestry and Agriculture. Nicholas Institute for Environmental Policy Solutions, Duke University.
http://nicholas.duke.edu/institute/offsetseries4.pdf

Replace With:
Jenkins, Olander, and Murray (2009): Addressing Leakage in a Greenhouse Gas Mitigation Offsets Program for Forestry and Agriculture. Nicholas Institute for Environmental Policy Solutions, Duke University.
http://nicholasinstitute.duke.edu/climate/policydesign/offsetseries4

Page Numbers for Correction: References-21
The following reference was incomplete:

Original Text:
Market Advisory Committee (2007): Recommendations for Designing a Greenhouse Gas Cap-and-Trade System.
http://climatechange.ca.gov/market_advisory_committee/index.html

Replace With:
Market Advisory Committee (2007): Recommendations for Designing a Greenhouse Gas Cap-and-Trade System for California.
http://climatechange.ca.gov/market_advisory_committee/index.html

Page Numbers for Correction: References-21
The following reference was incomplete:

Original Text:
Murtishaw and Griffin (2007): Joint California Public Utilities Commission and Energy Commission Staff Proposal for an Electricity Retail Provider GHG Reporting Protocol. California Public Utilities Commission and Energy Commission.
ftp://ftp.cpuc.ca.gov/puc/energy/electric/climate+change/Joint+Staff+GHG+Reporting+Proposal.pdf

Replace With:

Murtishaw and Griffin (2007): Joint California Public Utilities Commission and California Energy Commission Staff Proposal for an Electricity Retail Provider GHG Reporting Protocol. California Public Utilities Commission and California Energy Commission.
ftp://ftp.cpuc.ca.gov/puc/energy/electric/climate+change/Joint+Staff+GHG+Reporting+Proposal.pdf

Page Numbers for Correction: References-21
The following reference was incomplete:

Original Text:
Nabuurs, G. J., O. Masera, et al. (2007). Forestry. Climate Change 2007: Mitigation of Climate Change. Contributions of Working Group III to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change. M. Apps and E. Calvo. New York, Cambridge University Press.
http://www.ipcc.ch/publications_and_data/ar4/wg3/en/ch9.html

Replace With:
Nabuurs et al. (2007). Forestry. In Climate Change 2007: Mitigation. Contribution of Working Group III to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA.
http://www.ipcc.ch/publications_and_data/ar4/wg3/en/ch9.html

Page Numbers for Correction: References-21
The following reference was incomplete:

Original Text:
Nepstad et al. (2010): Brazil's Emerging Sectoral Framework for Reducing Emissions from Deforestation and Degradation (REDD) and the Potential to Deliver Greenhouse Gas Emissions Offsets from Avoided Deforestation in the Amazon's Xingu River Basin. Electric Power Research Institute.

Replace With:
Brazil's Emerging Sectoral Framework for Reducing Emissions from Deforestation and Degradation (REDD) and the Potential to Deliver Greenhouse Gas Emissions Offsets from Avoided Deforestation in the Amazon's Xingu River Basin. Electric Power Research Institute. 2010. http://tropicalforestgroup.org/pdf/Xingubasin.pdf

Page Numbers for Correction: References-21
The following reference was incomplete:

Original Text:
New Zealand Ministry for the Environment (2008): The Framework for a New Zealand Emissions Trading Scheme - Core Design Features.
http://www.mfe.govt.nz/publications/climate/framework-emissions-trading-scheme-sep07/html/page6.html

Replace With:
New Zealand Ministry for the Environment (2008): The Framework for a New Zealand Emissions Trading Scheme – Chapter 4: Core Design Features.

http://www.mfe.govt.nz/publications/climate/framework-emissions-trading-scheme-sep07/html/page6.html

Page Numbers for Correction: References-21
The following reference was incomplete:

Original Text:
Olander and Murray (2008): Addressing Impermanence Risk and Liability in Agriculture, Land Use Change, and Forest Carbon Projects. Nicholas Institute for Environmental Policy Solutions, Duke University. http://nicholas.duke.edu/institute/offsetseries3.pdf

Replace With:
Olander and Murray (2008): Addressing Impermanence Risk and Liability in Agriculture, Land Use Change, and Forest Carbon Projects. Nicholas Institute for Environmental Policy Solutions, Duke University.
http://nicholasinstitute.duke.edu/climate/policydesign/offsetseries3

Page Numbers for Correction: References-21
The following reference was incomplete:

Original Text:
Olander and Murray (2008): Offsets: An Important Piece of the Climate Policy Puzzle. Nicholas Institute for Environmental Policy Solutions, Duke University.
http://nicholas.duke.edu/institute/offsetseries1.pdf

Replace With:
Olander and Murray (2008): Offsets: An Important Piece of the Climate Policy Puzzle. Nicholas Institute for Environmental Policy Solutions, Duke University.
http://nicholasinstitute.duke.edu/mitigationbeyondcap/offsetseries1

Page Numbers for Correction: References-21
The following reference was incomplete:

Original Text:
Olander and Murray (2008): Treatment of Early Agricultural and Forestry Actors in a Federal Cap-and-Trade. Nicholas Institute for Environmental Policy Solutions, Duke University. http://nicholas.duke.edu/institute/offsetseries2.pdf

Replace With:
Olander and Murray (2008): Treatment of Early Agricultural and Forestry Actors in a Federal Cap-and-Trade. Nicholas Institute for Environmental Policy Solutions, Duke University. http://nicholasinstitute.duke.edu/mitigationbeyondcap/offsetseries2

Page Numbers for Correction: References-22
The following reference was incomplete:

Original Text:
Olander et al. (2008): Designing Offsets Policy for the United States. Nicholas Institute for Environmental Policy Solutions.

Replace With:
Olander et al. (2008): Designing Offsets Policy for the United States. Nicholas Institute for Environmental Policy Solutions. http://nicholasinstitute.duke.edu/climate/policydesign/designing-offsets-policy-for-the-u.s

Page Numbers for Correction: References-22
The following reference was incomplete:

Original Text:
Olander, Cooley, and Murray (2010): Policy Options for Transitioning from Voluntary to Federal Offsets Markets. Nicholas Institute for Environmental Policy Solutions, Duke University. http://nicholas.duke.edu/institute/offsets.01.06.10.pdf

Replace With:
Olander, Cooley, and Murray (2010): Policy Options for Transitioning from Voluntary to Federal Offsets Markets. Nicholas Institute for Environmental Policy Solutions, Duke University. http://nicholasinstitute.duke.edu/mitigationbeyondcap/policy-options-for-transitioning-from-voluntary-to-federal-offsets-markets

Page Numbers for Correction: References-22
The following reference is duplicative:

Delete Original Text:

Olander, Lydia (2008): Designing Offsets Policy for the United States. Nicholas Institute for Environmental Policy Solutions, Duke University. http://nicholas.duke.edu/institute/offsetspolicy.pdf

Page Numbers for Correction: References-22
The following reference was incomplete:

Original Text:
Olander, Profeta, and Galik (2010): Sticking Points in Offsets Policy. Nicholas Institute for Environmental Policy Solutions, Duke University. http://nicholas.duke.edu/institute/offsets.memo.01.07.10.pdf

Replace With:
Olander, Profeta, and Galik (2010): Sticking Points in Offsets Policy. Nicholas Institute for Environmental Policy Solutions, Duke University.
http://nicholasinstitute.duke.edu/mitigationbeyondcap/sticking-points-in-offsets-policy

Page Numbers for Correction: References-22
The following reference was incomplete:

Original Text:
Paustian, K. et al. (2006): IPCC Guidelines for National Greenhouse Gas Inventories. Volume 4, Chapter 1.
http://www.ipccnggip.iges.or.jp/public/2006gl/pdf/4_Volume4/V4_01_Ch1_Introduction.pdf

Replace With:
Paustian et al. (2006): IPCC Guidelines for National Greenhouse Gas Inventories. Volume 4, Chapter 1. http://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/4_Volume4/V4_01_Ch1_Introduction.pdf

Page Numbers for Correction: References-22
The following reference was incomplete:

Original Text:
Price et al. (2009): Electricity Leakage Analysis Report. Western Climate Initiative.
http://www.westernclimateinitiative.org/component/remository/Electricity-Team-Documents/Electricity-Leakage-Analysis-Summary-Report/

Replace With:
Price et al. (2009): Electricity Leakage Analysis Summary Report. Western Climate Initiative. http://www.westernclimateinitiative.org/component/remository/Electricity-Team-Documents/Electricity-Leakage-Analysis-Summary-Report/

Page Numbers for Correction: References-22
The following reference was incomplete:

Original Text:
Reynolds, Bill (2008): Do We Need Financial Additionality? Environmental Markets Association. http://www.environmentalmarkets.org/galleries/default-file/EF0308_Marketview.pdf.

Replace With:
Reynolds, Bill (2008): Do We Need Financial Additionality? Environmental Finance.
http://www.environmentalmarkets.org/galleries/default-file/EF0308_Marketview.pdf

Page Numbers for Correction: References-22
The following reference was incomplete:

Original Text:
Roland-Holst, David (2010): Climate Action for Sustained Growth: Analysis of ARB's Scoping Plan. http://www.arb.ca.gov/board/books/2010/042110/10-3-6-david-roland-holst-panelist.pdf

Replace With:
Roland-Holst, David (2010): Roland-Holst Presentation: Climate Action for Sustained Growth: Analysis of ARB's Scoping Plan.
http://www.arb.ca.gov/board/books/2010/042110/10-3-6-david-roland-holst-panelist.pdf

Page Numbers for Correction: References-22
The following reference was incomplete:

Original Text:
Ruesch and Gibbs (2008): New IPCC Tier-1 Global Biomass Carbon Map For the Year 2000. Oak Ridge National Laboratory. http://cdiac.ornl.gov

Replace With:
Ruesch and Gibbs (2008): New IPCC Tier-1 Global Biomass Carbon Map For the Year 2000. Oak Ridge National Laboratory.
http://cdiac.ornl.gov/epubs/ndp/global_carbon/carbon_documentation.html

Page Numbers for Correction: References-23
The following reference was incomplete:

Original Text:
Sathaye et al. (2010): Industrial Energy Efficiency Technologies in Integrated Assessment Models. Lawrence Berkeley National Laboratory.
http://eetd.lbl.gov/ea/ies/ppt/ee.pdf

Replace With:
Sathaye et al. (2006): Representation of Industrial Energy Efficiency Technologies in Integrated Assessment Models. Lawrence Berkeley National Laboratory.
http://eetd.lbl.gov/ea/ies/ppt/ee.pdf

Page Numbers for Correction: References-23
The following reference was present in a footnote of the staff report but not in the references list:

Add New Text:
Sathaye, Jayant, et al. Bottom-up Representation of Industrial Energy Efficiency Technologies in Integrated Assessment Models for the Cement Sector. Lawrence Berkeley National Laboratory, Environmental Energy Technologies Division. 2010.

Page Numbers for Correction: References-23
The following reference was incomplete:

Original Text:
Schmidt, Helme, Lee, and Houdashelt (2008): Sector-based Approach to the post-2012 Climate Change Policy Architecture. Center for Clean Air Policy. http://www.ccap.org/docs/resources/539/CPOL8-5_05_Schmidt%20%282%29.pdf.

Replace With:
Schmidt et al. (2008): Sector-based Approach to the post-2012 Climate Change Policy Architecture. Center for Clean Air Policy. http://www.ccap.org/docs/resources/539/CPOL8-5_05_Schmidt%20%282%29.pdf.

Page Numbers for Correction: References-23
The following reference was incomplete:

Original Text:
Schneider, Lambert (2007): Is the CDM Fulfilling its Environmental and Sustainable Development Objectives? An Evaluation of the CDM and Options for Improvement. Institute for Applied Ecology. http://oeko.de/oekodoc/622/2007-162-en.pdf.

Replace With:
Schneider, Lambert (2007): Is the CDM Fulfilling its Environmental and Sustainable Development Objectives? An Evaluation of the CDM and Options for Improvement. Oeko Institute e.V. Institute for Applied Ecology. http://oeko.de/oekodoc/622/2007-162-en.pdf.

Page Numbers for Correction: References-23
The following reference was present in a footnote of the staff report but not in the references list:

Add New Text:
Oropeza (2009). Senate Bill 104.

Page Numbers for Correction: References-23
The following reference was present in a footnote of the staff report but not in the references list:

Add New Text:
Senate Bill 115 (Solis, Statutes of 1999, chapter 690); California Government Code § 65040.12(c)

Page Numbers for Correction: References-23
The following reference was incomplete:

Original Text:
United States Department of Energy (2002): Martinez Refinery Completes Plant-wide Energy Assessment.
http://www1.eere.energy.gov/industry/bestpractices/pdfs/bp_cs_martinez.pdf

Replace With:
United States Department of Energy (2002): Best Practices Assessment Case Study. Martinez Refinery Completes Plant-wide Energy Assessment.
http://www1.eere.energy.gov/industry/bestpractices/pdfs/bp_cs_martinez.pdf

Page Numbers for Correction: References-23
The following reference was incomplete:

Original Text:
United States Department of Energy (2007): Preheated Combustion Air.
http://www1.eere.energy.gov/industry/bestpractices/pdfs/et_preheated.pdf

Replace With:
United States Department of Energy (2007): Process Heating Tip Sheet Industrial Technologies Program. Preheated Combustion Air.
http://www1.eere.energy.gov/industry/bestpractices/pdfs/et_preheated.pdf

Page Numbers for Correction: References-24
The following reference was incomplete:

Original Text:
Wara, Michael (2008): Measuring the Clean Development Mechanisms Performance and Potential. UCLA Law Review 1759. http://uclalawreview.org/?p=386

Replace With:
Wara, Michael (2008): Measuring the Clean Development Mechanisms Performance and Potential. UCLA Law Review 1759. http://iis-db.stanford.edu/pubs/22226/wara_law_review_ucla.pdf

Page Numbers for Correction: References-24
The following reference was incomplete:

Original Text:
Xu et al. (2010): Development of Bottom-up Representation of Industrial Energy Efficiency Technologies in Integrated Assessment Models for the Iron and Steel Sector. Lawrence Berkeley National Laboratory.

Replace With:
Xu et al. (2010): Development of Bottom-up Representation of Industrial Energy Efficiency Technologies in Integrated Assessment Models for the Iron and Steel Sector. Lawrence Berkeley National Laboratory.
http://ies.lbl.gov/drupal.files/ies.lbl.gov.sandbox/4314E_0.pdf

Page Number for Correction: References-26
The journal reference was not properly indicated for the following reference:

Original Text:
Anger et al. (2009): Linking the EU Emissions Trading Scheme. Springer Science.
http://www.springerlink.com/content/a30u5l723g2nx4h4/fulltext.pdf

Replace With:
Anger et al. (2009): Linking the EU Emissions Trading Scheme. Mitigation and Adaptation Strategies for Global Change, Volume 14, Number 5, 379-398,
http://www.springerlink.com/content/a30u5l723g2nx4h4/fulltext.pdf

Page Number for Correction: References-29
The following is a duplicate reference:

Bushnell and Chen (2008): Regulation, Allocation, and Leakage in Cap-and- Trade Markets for CO_2. University of California, Berkeley.

Page Number for Correction: References-29
The journal reference was not properly indicated for the following reference:

Original Text:
Bye and Brovoll (2008): Multiple Instruments to Change Energy Behavior. Springer Science. http://www.springerlink.com/content/703514300g3340hk/fulltext.pdf

Replace With:
Bye and Brovoll (2008): Multiple Instruments to Change Energy Behavior. Energy Efficiency, Volume 1, Number 4, 373-386.
http://www.springerlink.com/content/703514300g3340hk/fulltext.pdf

Page Number for Correction: References-36
The following reference indicated an incorrect year:

Original Text:
Dinan and Rogers (2007): Distributional Effects of Carbon Allowance Trading: How Government Decisions Determine Winners and Losers. Congressional Budget Office. http://findarticles.com/p/articles/mi_hb3356/is_2_55/ai_n28933894/?tag=content; col1

Replace With:
Dinan and Rogers (2002): Distributional Effects of Carbon Allowance Trading: How Government Decisions Determine Winners and Losers. Congressional Budget Office. http://findarticles.com/p/articles/mi_hb3356/is_2_55/ai_n28933894/?tag=content; col1

Page Number for Correction: References-37
The following reference indicated an incorrect year:

Original Text:
Ellerman et al. (2008): Bringing Transportation into a Cap-and-Trade Regime.
Replace With:
Ellerman et al. (2006): Bringing Transportation into a Cap-and-Trade Regime. http://web.mit.edu/ceepr/www/publications/jp-pubsabstracts/Reports/JPRep136.pdf

Page Number for Correction: References-37
The following reference is duplicative:

Ellerman et al. (2008): Cap-and-trade: Contributions to the Design of a U.S. Greenhouse Gas Program. Massachusetts Institute of Technology. http://web.mit.edu/ceepr/www/publications/DDCF.pdf

Page Number for Correction: References-38
The following reference was incomplete:

Original Text:
EU (2009): EU Comm Paper - Carbon Leakage.
http://www.google.com/url?sa=t&source=web&cd=1&ved=0CBIQFjAA&url=http%3A%2F%2Fwww.euractiv.com%2F29%2Fimages%2FComm%2520paper%2520carbon%2520leakage%2520180908_tcm29-175576.doc&rct=j&q=This%20nonpaper%20reports%20on%20progress%20achieved%20with%20the%20a

Replace With:
European Commission (2009) Commission Services Paper on Energy Intensive Industries Exposed to Significant Risk of Carbon Leakage

http://www.google.com/url?sa=t&rct=j&q=commission%20services%20paper%20on%20energy%20intensive%20industries%20exposed&source=web&cd=5&ved=0CDgQFjAE&url=http%3A%2F%2Fcw.routledge.com%2Ftextbooks%2Feresources%2F9781849712040%2FMassai2.doc&ei=Dc2hTqTQFKXgiAKm0qhz&usg=AFQjCNHoyd4VfE05cYk60qDhoIYe6w2UDQ&cad=rja

Page Number for Correction: References-39
The following reference was incomplete:

Original Text:
EU Commission Staff (2008): Working Document to Extend the EU ETS.

Replace With:
EU Commission Staff (2008): Commission staff working document - Accompanying document to the Proposal for a Directive of the European Parliament and of the Council amending Directive 2003/87/EC so as to improve and extend the EU greenhouse gas emission allowance trading system - Summary of the impact assessment {COM(2008) 16 final} {SEC(2008) 52} /* SEC/2007/0053 final */ http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=CELEX:52008SC0053:EN:HTML

Page Number for Correction: References-40
The following reference was incomplete:
Original Text:
Frankel, Jeffrey (2008): Options for Addressing the Leakage/Competitiveness Issue in

Replace With:
Frankel, Jeffrey (2008): Options for Addressing the Leakage/Competitiveness Issue in Climate Change Policy Proposals
http://www.brookings.edu/events/2008/0609_climate_trade.aspx

Page Number for Correction: References-41 and References-49
The following reference was unintentionally severed:

Original Text (part 1):
McKinsey & Company (2009): Pathways to a Low-Carbon Economy (Version 2 of the

Original Text (part 2):
Global GHG Abatement Cost Curve).
https://solutions.mckinsey.com/climatedesk/default/en-us/governments/contact_us/fullreport.aspx

Replace With:
McKinsey & Company (2009): Pathways to a Low-Carbon Economy (Version 2 of the Global GHG Abatement Cost Curve).
https://solutions.mckinsey.com/climatedesk/default/en-us/governments/contact_us/fullreport.aspx

Page Number for Correction: References-43
The following reference was mistitled:

Original Text:
Hollady and Livermore (2010): Clear Act and the Economy. Institute for Policy Integrity. http://policyintegrity.org/documents/ClearandTheEconomy.pdf

Replace With:
Hollady and Livermore (2010): CLEAR and the Economy. Institute for Policy Integrity. http://policyintegrity.org/documents/ClearandTheEconomy.pdf

Page Number for Correction: References-45
The following reference was mistitled:

Original Text:
KEMA Inc. (2009): Cross-Border Emissions Credit Trading Between California and Baja California, Mexico. http://www.energy.ca.gov/2009publications/CEC-600-2009-004/CEC-600-2009-004.PDF

Replace With:
KEMA Inc. (2009): Evaluation of the Requirements Necessary to Introduce Cross-Border Emissions Credit Trading Between California and Baja California, Mexico.
http://www.energy.ca.gov/2009publications/CEC-600-2009-004/CEC-600-2009-004.PDF

Page Number for Correction: References-46
The following two references were unintentionally combined:

Original Text:
Keohane, Nat (2008): Community-based Energy Policy: A Practical Approach to Carbon Reduction. Environmental Defense Fund.
http://www.rff.org/Events/Pages/Cost_Containment_USGHG.aspx

Replace With:
Kellett (2007): Community-based Energy Policy: A Practical Approach to Carbon Reduction. Journal of Environmental Planning and Management. Volume 50, Number 3, 381-396 May 2007

And

Keohane (2008): Environmental Defense Fund Slides. Presented at Resources for the Future March 19th, 2008 Panel on Managing Costs in a U.S. GHG Trading Program. http://www.rff.org/Events/Documents/USHGHG-Keohane.pdf

Page Number for Correction: References-46
The following reference was incomplete:

Original Text:
Lawrence Berkeley National Laboratory (2008): Energy Efficiency and Cost Saving Opportunities for the Fruit and Vegetable Processing Industry. http://www.energystar.gov/ia/business/industry/Fruit_and_Vegetables_Energy_Guide.pdf

Replace With:
Masanet et al (2008): Energy Efficiency and Cost Saving Opportunities for the Fruit and Vegetable Processing Industry. Lawrence Berkeley National Laboratory. http://www.energystar.gov/ia/business/industry/Fruit_and_Vegetables_Energy_Guide.pdf

Page Number for Correction: References-47
The following reference was incomplete:

Original Text:
Lawrence Berkely National Laboratory (2004): Profile of the Petroleum Refining Industry in California. http://ies.lbl.gov/iespubs/55450.pdf

Replace With:
Wornell and Galitsky (2004): Profile of the Petroleum Refining Industry in California. Lawrence Berkeley National Laboratory. http://ies.lbl.gov/iespubs/55450.pdf

Page Number for Correction: References-47 and References-48
The following reference was unintentionally severed and incomplete:

Original Text (Part 1):
Lejano and Hirose (2005): Testing the Assumptions Behind Emission Trading in Non-

Original Text (Part 2):
Market Goods.

http://www.sciencedirect.com/science?_ob=ArticleURL&_udi=B6VP6-4GCX1TT-1&_user=1928924&_coverDate=08/31/2005&_rdoc=1&_fmt=high&_orig=search&_sort=d&_docanchor=&view=c&_searchStrId=1426865126&_rerunOrigin=google&_acct=C000055388&_version=1&_urlVersion=0&_userid=1928924&md5=2ecbdca74e20ef6a1bff2ff4ffc865d3

Replace With:
Lejano, Raul P. and Rei Hirose (2005) Testing the assumptions behind emissions trading in non-market goods: the RECLAIM program in Southern California. Environmental Science & Policy. Volume 8, Issue 4, August 2005, Pages 367-377
http://www.sciencedirect.com/science?_ob=ArticleURL&_udi=B6VP6-4GCX1TT-1&_user=1928924&_coverDate=08/31/2005&_rdoc=1&_fmt=high&_orig=search&_sort=d&_docanchor=&view=c&_searchStrId=1426865126&_rerunOrigin=google&_acct=C000055388&_version=1&_urlVersion=0&_userid=1928924&md5=2ecbdca74e20ef6a1bff2ff4ffc865d3

Page Number for Correction: References-48
The following reference was incomplete:

Original Text:
Market Efficiency Board. Tufts University.
http://www.rff.org/Events/Pages/Cost_Containment_USGHG.aspx

Replace With:
Metcalf, Gilbert E. (2008) Mitigating Costs in a U.S. GHG Trading Program: Carbon Market Efficiency Board. Presented at Resources for the Future March 19th, 2008 Panel on Managing Costs in a U.S. GHG Trading Program
http://www.rff.org/Events/Documents/USGHG-Metcalf.pdf

Page Number for Correction: References-48
The following reference was incomplete:

Original Text:
Mason, Joseph (2009): Economic Policy Risks. US Climate Task Force. Massachusetts Institute of Technology. http://web.mit.edu/ceepr/www/publications/jp-pubsabstracts/Reports/JPRep136.pdf

Replace With:
Mason, Joseph (2009): Economic Policy Risks of Cap and Trade for Carbon Emissions: A Monetary Economist's View of Cap and Trade Market and Carbon Market Efficiency Board Designs. US Climate Task Force. Massachusetts Institute of Technology.
http://web.mit.edu/ceepr/www/publications/jp-pubsabstracts/Reports/JPRep136.pdf

Page Number for Correction: References-48
The following reference contained an incorrect date:

Original Text:
McAllister, Lesley (2006): Beyond Playing "Banker": The Role of the Regulatory Agency in Emissions Trading. University of San Diego.
http://papers.ssrn.com/sol3/papers.cfm?abstract_id=929532

Replace With:
McAllister, Lesley (2010): Beyond Playing "Banker": The Role of the Regulatory Agency in Emissions Trading. University of San Diego.
http://papers.ssrn.com/sol3/papers.cfm?abstract_id=929532

Page Number for Correction: References-49
The following reference was incomplete:

Original Text:
Monast et al. (2009): Regulating Emission Allowances as Financial Instruments. Duke University. http://nicholasinstitute.duke.edu/climate/carbon-market-oversight/climate-change-
and-financial-markets-regulating-the-trade-side-of-cap-and-trade

Replace With:
Monast et al. (2009): US Carbon Market Design: Regulating Emission Allowances as Financial Instruments. Duke University.
http://nicholasinstitute.duke.edu/climate/carbon-market-oversight/climate-change-
and-financial-markets-regulating-the-trade-side-of-cap-and-trade

Page Number for Correction: References-61
The following reference contained a typo:

Original Text:
"Unite Kingdom National Audit Office (2009): Review of the EU ETS.
http://www.ivl.se/download/18.360a0d56117c51a2d30800072915/B1591.pdf"

Replace With:
"United Kingdom National Audit Office (2009): Review of the EU ETS.
http://www.ivl.se/download/18.360a0d56117c51a2d30800072915/B1591.pdf"

Page Number for Correction: References-64
The following reference was incomplete:

Original Text:
“Western States Petroleum Association (2009): Petroleum 101: The Petroleum Industry in”

Replace With:
“Western States Petroleum Association (2009): Petroleum 101: The Petroleum Industry in California: Adequate, Reliable, Affordable Energy in a Low-Carbon World.”

Page Number for Correction: References-66
The following reference was incomplete:

Original Text:
Avissar and Werth (2004): Global Hydroclimatological Teleconnections Resulting from Tropical Deforestation. Journal of Hydrometeorology.

Replace With:
Avissar, R. and Werth D. (2005) Global Hydroclimatological Teleconnections Resulting from Tropical Deforestation. Journal of Hydrometeorology, April, Volume 6, Number 2, pp 134–145. http://journals.ametsoc.org/doi/abs/10.1175/JHM406.1

Page Number for Correction: References-67
The following reference was incorrect:

Original Text:
California Air Resources Board and Western States Petroleum Association (2009): Air Quality Update.
http://www.wspa.org/uploads/documents/Energy%20Alerts/Air%20Quality%20Fact%20Sheet%20-%20California.pdf

Replace With:
Western States Petroleum Association (2009) Air Quality Update Newsletter.
http://www.wspa.org/uploads/documents/Energy%20Alerts/Air%20Quality%20Fact%20Sheet%20-%20California.pdf

Page Number for Correction: References-67
The following reference was incomplete:

Original Text:
California Energy Commission (2009): AB 1613: Guidelines, Forms, and Response to Comments. http://www.energy.ca.gov/wasteheat/documents/2009-10-12_workshop/presentations/Arthur_Soinski_Presentation_10-12-2009.pdf

Replace With:
California Energy Commission (2009): Waste Heat and Carbon Emissions Reduction Act. AB 1613: Guidelines, Forms, and Response to Comments.
http://www.energy.ca.gov/wasteheat/documents/2009-10-12_workshop/presentations/Arthur_Soinski_Presentation_10-12-2009.pdf

Page Number for Correction: References-68
The following reference was incorrect:

Original Text:
Darrow et al. (2009): CHP Market Assessment. IFC International.
http://www.energy.ca.gov/2009_energypolicy/documents/2009-07-23_workshop/presentations/01_ICF_CHP_Market_Assessment_Presentation.pdf

Replace With:
Darrow et al. (2009): CHP Market Assessment. ICF International.
http://www.energy.ca.gov/2009_energypolicy/documents/2009-07-23_workshop/presentations/01_ICF_CHP_Market_Assessment_Presentation.pdf

Page Numbers for Correction: References-70
The following reference was incomplete:

Original Text:
Pedroni, Lucio (2008): REDD Methodology.

Replace With:
Pedroni, Lucio (2008): Draft REDD Methodology. Global Change Group, CATIE

Page Numbers for Correction: References-70
The following reference was incomplete:

Original Text:
Nepstad et al. (2010): REDD+ in the Post-Copenhagen World: Recommendations for Interim Public Finance. O2 Monitor for CO_2 Monitor

Replace With:
Nepstad et al. (2010): REDD+ in the Post-Copenhagen World: Recommendations for Interim Public Finance. Amazon Environmental Research Institute (IPAM), Woods Hole Research Center and Environmental Defense Fund.

Page Numbers for Correction: References-71
The following reference was incomplete:

Original Text:
PEW Center on Global Climate Change (2008): Coverage of Natural Gas Emissions and Flows under a GHG Cap and Trade.
http://www.pewclimate.org/docUploads/NaturalGasPointofRegulation09.pdf

Replace With:
Bluestein, Joel (2008): Coverage of Natural Gas Emissions and Flows under a GHG Cap and Trade. PEW Center on Global Climate Change.
http://www.pewclimate.org/docUploads/NaturalGasPointofRegulation09.pdf

Page Numbers for Correction: References-71
The following reference was incomplete:

Original Text:
Potomac Economics (2009): Report on the Secondary Market for RGGI CO_2 Allowances: Third Quarter 2009.

Replace With:
Potomac Economics (2009): Report on the Secondary Market for RGGI CO_2 Allowances: Third Quarter 2009. RGGI, Inc.

Page Numbers for Correction: References-71
The following reference was incomplete:

Original Text:
Reed et al. (2009): New Mechanisms for Financing Mitigation: Transforming Economies Sector by Sector.

Replace With:
Reed et al. (2009): New Mechanisms for Financing Mitigation: Transforming Economies Sector by Sector. WWF Macroeconomics for Sustainable Development Program Office.

Page Numbers for Correction: References-71
The following reference was incomplete:

Original Text:
Regional Greenhouse Gas Initiative, Inc. (2009): Auction Notice for CO_2 Allowance Auction 2 on September 9, 2009.

Replace With:
Regional Greenhouse Gas Initiative, Inc. (2009): Auction Notice for CO_2 Allowance Auction 5 on September 9, 2009.

Page Numbers for Correction: References-71
The following reference was incomplete:

Original Text:
Rehels-Boyd, Catherine (2010): The Petroleum Industry and Refining in California. Western States Petroleum Association.

Replace With:
Reheis-Boyd, Catherine (2010): Presentation: The Petroleum Industry and Refining in California. Western States Petroleum Association.

Page Numbers for Correction: References-71
The following reference was incomplete:

Original Text:
Schneider and Cames (2009): A Framework for a Sectoral Crediting Mechanism in a Post-2012 Climate Regime. Institute for Applied Ecology.

Replace With:
Schneider and Cames (2009): A Framework for a Sectoral Crediting Mechanism in a Post-2012 Climate Regime : Report for the Global Wind Energy Council. Oeko Institut e.V. Institute for Applied Ecology.

Page Numbers for Correction: References-71
The following reference was incomplete:

Original Text:
Schneider and Cames (2009): Sectoral Crediting Mechanism Design. Institute for Applied Ecology.

Replace With:
Schneider and Cames (2009): Presentation: Sectoral Crediting Mechanism Design: Results of a Study Commissioned by the Global Wind Energy Council. Oeko Institut e.V. Institute for Applied Ecology.

Page Numbers for Correction: References-72
The following reference was incomplete:

Original Text:
SRI International, Center of Excellence in Energy (2009): Integrated Energy Policy Report - Biopower in CA Docket #09-IEP-1G.

Replace With:
SRI International, Center of Excellence in Energy (2009): Letter to the California Energy Commission. Integrated Energy Policy Report - Biopower in CA Docket #09-IEP-1G.

Page Numbers for Correction: References-72
The following reference was incomplete:

Original Text:
State of California Legislature (1973): Z'Berg-Nejedly Forest Practice Act. http://www.fire.ca.gov/ResourceManagement/pdf/2000RULE198254.pdf Table for CO_2 Requirements.

Replace With:
Z'Berg-Nejedly Forest Practices Act. 1973. Division 4, Chapter 8, Public Resources Code, State of California, Sacramento, CA. Table for CO_2 Requirements. http://www.fire.ca.gov/ResourceManagement/pdf/2000RULE198254.pdf

Page Numbers for Correction: References-72
The following reference was incomplete:

Original Text:
Thorneloe et al. (2005): Moving from Solid Waste Disposal to Materials Management in the US. United States Environmental Protection Agency, RTI International. http://programacyma.com/docs%20ppp/Informacion%20-%20Gestion%20Integral%20de%20Residuos%20%28GIR%29/Tratamiento/USEPA-MSW-DMT-ThorneloeA209Final.pdf

Replace With:
Thorneloe et al. (2005): Moving from Solid Waste Disposal to Materials Management in the United States. In Proceedings, 10th International Waste Management and Landfill Symposium, Sardinia, ITALY, October 03 - 07, 2005. Euro Waste srl, Padova, Italy, NA. http://programacyma.com/docs%20ppp/Informacion%20-%20Gestion%20Integral%20de%20Residuos%20%28GIR%29/Tratamiento/USEPA-MSW-DMT-ThorneloeA209Final.pdf

Page Numbers for Correction: References-72
The following reference was incomplete:

Original Text:
Thorneloe et al. (2007): Application of the US Decision Support Tool for Materials and Waste Management. United States Environmental Protection Agency, RTI International. http://www.ncbi.nlm.nih.gov/pubmed/17433663

Replace With:
Thorneloe et al. (2007): Application of the US Decision Support Tool for Materials and Waste Management. Waste Management 27: 1006-1020. http://www.ncbi.nlm.nih.gov/pubmed/17433663

Page Numbers for Correction: References-72
The following reference was incomplete:

Original Text:
United States Environmental Protection Agency (2009): Federal Register, Rules and Regulations pt 1.

Replace With:
United States Environmental Protection Agency (2009): Federal Register Vol. 74, No. 209, 56341-56346, Rules and Regulations.

Page Numbers for Correction: References-72
The following reference was incomplete:

Original Text:
United States Environmental Protection Agency (2009): Federal Register, Rules and Regulations pt 2.

Replace With:
United States Environmental Protection Agency (2009): Federal Register Vol. 74, No. 209, 56491-56503, Rules and Regulations.

Page Numbers for Correction: References-72
The following reference was incomplete:

Original Text:
Ward et al. (2008): The Role of Sector No-lose Targets in Scaling Up Finance for Climate Change Mitigation Activities in Developing Countries.

Replace With:
Ward et al. (2008): The Role of Sector No-lose Targets in Scaling Up Finance for Climate Change Mitigation Activities in Developing Countries. International Climate Division Department for Environment, Food, and Rural Affairs (DEFRA) United Kingdom.

Page Numbers for Correction: References-72
The following reference was incomplete:

Original Text:
Wickizen, Doug (2009): Barriers to Biomass Feedstock. CalFire. http://www.energy.ca.gov/2009_energypolicy/documents/2009-04-21_workshop/presentations/10-Wickizer_CA_Dept_of_ForestryBarriers_to_Biomass_Feedstock_4-21-09.pdf

Replace With:
Wickizer, Doug (2009): Barriers to Biomass Feedstock:Integrated Energy Policy Report Workshop April 21, 2009. CalFire http://www.energy.ca.gov/2009_energypolicy/documents/2009-04-21_workshop/presentations/10-Wickizer_CA_Dept_of_Forestry-Barriers_to_Biomass_Feedstock_4-21-09.pdf

ATTACHMENT C: ACRONYMS

AAQS	Ambient Air Quality Standards
ACR	American Carbon Registry
AF	Assistance Factor
ANSI	American National Standards Institute
APA	Administrative Procedure Act
API	American Petroleum Institute
ARB	California Air Resources Board
ARR	Auction Revenue Rights
ASTM	American Society for Testing and Materials
BACT	Best Available Control Technology
BOF	Board of Forestry and Fire Protection
CAA	Federal Clean Air Act
CAISO	California Independent System Operator
CAPCOA	California Air Pollution Control Officers Association
CAR	Climate Action Reserve
CBF	Community Benefits Fund
CCA	Coalition for Clean Air
CCAA	California Clean Air Act of 1988
CCGS	carbon capture and geologic sequestration
CCR	California Code of Regulations
CCS	carbon capture and sequestration
CDM	Clean Development Mechanism
CDPH	California Department of Public Health
CEC	California Energy Commission
CEE	customer energy efficiency
CEQA	California Environmental Quality Act
CFTC	Commodity Futures Trading Commission
CO_2	carbon dioxide
CO2e	carbon dioxide equivalent
CO_2-EOR	carbon dioxide-enhanced oil recovery
CHP	combined heat and power
CPUC	California Public Utilities Commission
CRA	Colorado River Aqueduct
CRT	Climate Reserve Tonne
CWB	Carbon Weighted Barrel
CWT	CO_2 Weighted Tonne
DoD	U.S. Department of Defense
DOE	U.S. Department of Energy
DOJ	Department of Justice
EAAC	Economic and Allocation Advisory Committee
EDU	Electrical Distribution Utilities
EE	energy efficiency
EEB	Emissions Efficiency Benchmark
EEI	Edison Electric Institute

EII	Solomon Energy Intensity Index
EIR	Environmental Impact Report
EJ	Environmental Justice
EJAC	Environmental Justice Advisory Committee
EJSM	Environmental Justice Screening Method
EPA	U.S. Environmental Protection Agency
ETS	Emissions Trading Scheme
EU ETS	European Union Emissions Trading System
FERC	Federal Energy Regulatory Commission
FPIC	Free Prior and Informed Consent
FSOR	Final Statement of Reasons
GAO	Government Accountability Office
GCF	Governor’s Climate and Forests Task Force
GFHP	gas-fired heat pump
GHG	greenhouse gas
GIS	geographic information system
HCP	Habitat Conservation Plan
HDPP	High Desert Power Project
HIA	Health Impact Assessment
HRA	Health Risk Assessment
IA	Implementation Agreement
IAF	International Accreditation Forum
IOU	investor-owned utility
IPCC	Intergovernmental Panel on Climate Change
IPP	independent power producer
ISO	International Organization for Standardization
ISOR	Initial Statement of Reasons
ITC	International Trade Commission
JPA	Joint Powers Agency
JUG	Joint Utilities Group
kW	kilowatts
LADWP	Los Angeles Department of Water and Power
LCFS	Low Carbon Fuel Standard
LDC	local distribution company
LMU	logical management unit
LTO	Licensed Timber Operator
LNG	liquefied natural gas
MJRP	Multi-Jurisdictional Retail Providers
mmBtu	millions of British thermal units
MMT	million metric tons
MRR	Mandatory Reporting of Greenhouse Gas Emissions Regulation
MRV	measurement, reporting and verification
$MTCO_2e$	metric ton of carbon dioxide equivalent
MTS	market tracking system
MWh	megawatt-hour
NAICS	North American Industry Classification System

NAAQS	National Ambient Air Quality Standards
NCCP	Natural Community Conservation Plans
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
NGL	Natural Gas Liquids
NOV	Notice of Violation
NOx	oxides of nitrogen
NREL	National Renewable Energy Laboratory
NSR	New Source Review
NYDEC	New York Department of Environmental Conservation
OAL	The California Office of Administrative Law
ODS	ozone depleting substance
OPR	Offset Project Registries
PDR	Preliminary Review Draft
POU	publicly owned utility
PSE	purchasing-selling entity
QE	qualified export
QF	qualified facility
NYSE	New York Stock Exchange
REC	Renewable Energy Credit
RECLAIM	Regional Clean Air Incentives Market Program
REDD	Reducing Emissions from Deforestation and Forest Degradation
RES	Renewable Electricity Standard
RGGI	Regional Greenhouse Gas Initiative
ROG	reactive organic gases
RPF	Registered Professional Forester
RPS	Renewable Portfolio Standard
SEC	Securities and Exchange Commission
RUS	Rural Utility Service
SFPUC	San Francisco Public Utilities Commission
SHA	Safe Harbor Agreement
SIP	State Implementation Plan
SMR	steam methane reformer
SMUD	Sacramento Municipal Utility District
SO_2	sulfur dioxide
SQL	structured query language
SRAC	Short Run Avoided Cost
TAD	through air drying technology
TE	trade exposure
TEAP	United Nations Technical and Economic Assessment Panel
TG	teragram
THP	timber harvest plan or timber harvesting permit
TREC	Tradable Renewable Energy Credit
VAE	voluntarily associated entity
VCS	Voluntary Carbon Standard
VOC	volatile organic compound

VRE	Voluntary Renewable Electricity
WAPA	Western Area Power Administration
WCI	Western Climate Initiative
WECC	Western Electricity Coordinating Council
WREGIS	Western Renewable Energy Generation Information System
WSSP	Western Systems Power Pool