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Clerk of the Board
California Air Resources Board
1001 I Street
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RE: Draft Final Comments on ARB's Proposed 15-Day Modifications to the Cap-and-Trade Regulation

Dear Board Members:

Southern California Gas Company (SoCalGas) and San Diego Gas and Electric Company (SDG&E), collectively the Sempra Energy Utilities (SEu), submit these written comments concerning the Proposed 15-Day Modifications to the California Cap on Greenhouse Gas Emissions and Market-based Compliance Mechanisms (Cap-and-Trade Regulation), posted July 25, 2011.

SoCalGas operates the nation's largest natural gas distribution utility which serves a population of 20.9 million through 5.8 million natural gas meters. SDG&E serves 3.4 million consumers through 1.4 million electric meters and more than 840,000 natural gas meters. SEu owns and operates natural gas and electric distribution facilities, electric generation, underground natural gas storage facilities, and natural gas transmission facilities.

Summary of Key Issues

Sempra Energy utilities will discuss four major policy issues in this filing. These issues focus on treating California ratepayers fairly, supporting California's utilities that have made good faith efforts to meet renewable energy regulations, and enabling regulations which meet California's greenhouse gas emission reduction rules without unduly constraining the natural gas and electric delivery system so critical to California's economic vitality.

- **Treatment of Out Of State Renewables:** The first key issue is the treatment of some out-of-state renewable energy contracts entered into to meet California's renewable goals. As proposed, the Cap-and-Trade Regulation does not treat California consumers fairly because it does not allow recognition of greenhouse gas reductions for some out-of-state renewable energy contracts. Such contracts fully comply with the Renewable Portfolio Standard and, accordingly, meet the GHG reduction objectives established by the State. The Regulation needs to be corrected to recognize GHG reduction value of these out of state contracts. Our comments below provide solutions for correcting the Proposed 15-day Modifications.

- **Resource Shuffling:** The second key issue is the definition of resource shuffling. As discussed in SEu's comments on the Mandatory Reporting Regulation (MRR), the resource shuffling provisions as proposed in the 15-day modifications are vague and overly broad, violate the intent of the cap-and-trade regulation, create the Commerce Clause issues, and contradict CPUC requirements of utilities to undertake least cost dispatch. While restrictions may be needed, it is important to draft such restrictions in a manner that does not treat legitimate electricity market transactions as a crime. The definition of Resource Shuffling must be changed and we offer appropriate revisions in the discussion in these comments. In addition, because such extensive changes are needed, we recommend that ARB follow-up with a stakeholder process, including a workshop and additional comments, to further refine the rules to meet the disparate concerns of market participants.

- **Allowance Allocation.** The third key issue is the allocation of auction revenues. ARB has demonstrated intent to allow the allocation of allowance revenue to assist in mitigating the compliance burden. The proposed regulation has language requiring rebates be provided on the fixed portion of utility bills or as a separate fixed credit or rebate and prohibits solely on a volumetric basis. This provision usurps the CPUC's exclusive jurisdiction over retail ratemaking and is illegal. Furthermore, the provision does not accomplish ARB's stated purpose – to provide a carbon price signal. ARB has adopted a methodology for the allocation of emissions allowances to utilities based on compliance burden, which does not provide a price signal. If allocation based on compliance burden is ARB policy, then the principle relied on to allocate allowances between utility customers should be the same.

- **Allowance Price Containment Reserve.** The fourth key issue is the allowance price containment reserve. SEu supports inclusion of the Allowance Price Containment Reserve in the Cap-and-Trade Regulation as an essential tool to address the potential for price spikes and a market meltdown that would overflow into electricity markets. SEu recommends ARB establish a procedure in the Cap-and-Trade regulation to replenish the reserve should it become depleted. The approach outlined below is only one of several alternatives to accomplish the market stabilization goal, but would ensure the Cap-and-Trade market will provide additional emissions reductions at a fair price.

This document is divided into two parts: detailed discussion and analysis of the key issues mentioned above and, a section-by-section analysis of the Cap-and-Trade Regulation with Sempra Energy utilities recommendations for clarification and changes.

I. Key Issue 1 – Modifications to Treatment of Out-of-State Renewables

A. All Out-of-State Renewable Energy Developed Pursuant to California's Renewable Portfolio Standard (RPS) Should Have Zero GHG Emissions

The Cap-and-Trade Regulation, with proposed changes in the 15-day Modifications, still does not recognize the greenhouse gas (GHG) reduction benefits of certain renewable contracts entered into to meet California's renewable goals. Specifically, the structure of the Cap-and-Trade Regulation does not account for the zero GHG attributes of the energy from the out-of-state wind contracts that SDG&E has entered into. SEu appreciates the efforts of ARB to develop an alternate approach to out-of-state renewable resources in the 15-day modifications; however, the regulations as proposed in the 15-day modifications are still insufficient. As a result, SDG&E would be required to retire allowances for these renewable resources, which are otherwise counted as renewable by California law, and whose operation results in reduced GHG emissions by backing down generation of fossil resources. The State's renewable programs are identified by the Air Resources Board (ARB) as one of the costliest GHG reduction measures and these costs should not be unnecessarily increased. It is only fair that SDG&E's customers and the State as a whole receive credit for the GHG attributes that they have already purchased.

a. California's Current RPS Program and it Prospective RPS program under SB x1 2 Both Recognize the GHG Emission Reductions Benefit of All Imported Electricity

Under California's current 20 percent Renewable Portfolio Standard (RPS) program, RPS-obligated load-serving entities (LSEs) must meet twenty percent of retail load with generation procured from renewable resources.[1] The RPS program permits procurement of renewable electricity from facilities located outside of California, and allows LSEs to apply this generation for RPS compliance, provided that certain requirements are met. In particular, the current statutory framework requires that energy be delivered into California in order to be RPS-eligible.

Out-of-state variable renewable generation may be delivered into California over a transmission path as a "firmed and shaped" contract structure or as "re-bundled" structure approved by the California Energy Commission (CEC).[2] In the latter example, an LSE "rebundles" energy by purchasing bundled renewable generation -- *i.e.*, energy plus renewable energy credits (RECs) -- from a facility located outside California, immediately resells the energy (but not the RECs) to the seller, and "re-bundles" the RECs with conventional generation imported to California.

The California Public Utilities Commission (CPUC) has confirmed that such transactions, which it classifies as "REC-only" transactions, satisfy the requirements for RPS compliance and offer GHG reduction benefits. Indeed, the CPUC has specifically noted that "REC-only transactions in which the RPS-eligible energy does not serve California load provide to California consumers the general benefits of increased use of renewable energy, such as reduction in the emission of greenhouse gases . . . that accrue because RPS-eligible generation has occurred within the [Western Electricity Coordinating Council ("WECC")]."[3] Thus, under the current RPS program, so long as the retail seller complies with the statute's delivery requirements and other rules surrounding RPS eligibility, the conventional generation re-bundled with RECs and imported to California is treated as renewable with all the renewable attributes including zero GHG emissions.

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[1] The 20% RPS Program is codified at California Public Utility Code §399.12. Recently adopted legislation, Senate Bill x1 2 increases this requirement to 33% by 2020. Senate Bill (SB) x1 2 (Stats. 2011, Ch. 1). SB x1 2 will become effective 90 days after the special legislative session has adjourned. The special legislative session is currently estimated to run through September 30, 2011. *See* Session Schedules, http://www.statescape.com/resources/sessions/sessionsnew.asp.

[2] CEC *Renewables Portfolio Standard Eligibility Guidebook* (3rd Ed., Jan. 2008), pp. 23-24, FN2

[3] D.10-03-021, *mimeo*, p. 27.

The current RPS program will be modified in accordance with SB x1 2 as it expands to a 33 percent RPS. SB x1 2 grandfathers transactions approved under the original RPS framework;[4] it also continues to treat the "re-bundled" transactions described above as RPS-eligible.[5] Notably, SBx1 2 eliminates the delivery requirement and permits RPS-obligated LSEs to satisfy RPS compliance obligations with out-of-state RECs that are not re-bundled with conventional generation for import into California.[6]

b. The Cap-and-Trade Regulation Would Negatively Impact SDG&E Ratepayers With Respect to Renewables Commitments Already Made

SDG&E has two wind contracts with projects that are currently producing energy in Montana (Glacier I and II) and has a signed contract to develop additional wind facilities in the same area (Rim Rock). SDG&E purchases a bundled renewable power product from the project owner and makes a simultaneous sale back at the project's busbar of conventional power. The CEC eligible firming-and-shaping method leaves SDG&E with the green attributes associated with the project. In 2013, SDG&E plans to re-bundle these green attributes with energy generated outside the State, but not in the NaturEner Power Watch, the balancing authority area containing the wind energy. In fact, there are no fossil resources located within that balancing authority area. These wind projects are expected to generate 1.2 million MWh annually.

The proposed cap-and-trade regulation would not recognize the GHG reducing impacts that these transactions have and would require SDG&E to obtain additional allowances associated with the amount of energy produced by these projects. Over the period to 2020, the treatment of out-of-state renewables in the 15-day modifications would add an additional $50 - $200 million dollars in ratepayer cost if ARB regulations are not revised to accurately account for these zero GHG renewable resources and would tighten the cap-and-trade market by adding more demand for allowances.[7]

The fact that these wind projects are in their own balancing authority (NaturEner Power Watch) with no fossil resources located within the balancing authority area, makes the replacement electricity requirements of the MRR impossible to meet. At least a third of the balancing authority areas in the WECC outside of California are small and controlled by a single entity and many control no load.[8] Therefore, renewable energy will be subject to market power in many of these small balancing authorities. The inconsistency between the current RPS program/SB x1 2 and the definition of replacement energy in the regulation will result in SDG&E customers paying *once* for renewable energy

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[4] SB x1 2, Sec. 13.

[5] SB X1 2, Sec. 22 allows "firmed and shaped" resources and unbundled RECs to count towards RPS with some quantitative limitations..

[6] *Id*.

[7] Valued at the reserve price ($10/MT) and price ceiling($40/MT) escalated at 7 percent, assuming the default emissions factor 0.428 MT/MWh.

[8] WECC, Map of Western Interconnection Balancing Authorities,

with all green attributes including the zero GHG attribute and then paying *again* for the GHG attribute by having to buy GHG allowances.[9]

c. The Cap-and-Trade Regulation Would Negatively Impact California Electricity Consumers With Respect of Future Out-of-State Renewable Energy Transactions That Meet RPS Requirements

Under SBx1 2, out-of-state renewable energy that is firmed and shaped and unbundled RECs sold to a retail seller would meet RPS requirements, subject to limitations. Such transactions would result in a reduction of greenhouse gases, meeting the purpose and intent of both the RPS and AB 32. However, under the Cap-and-Trade and Mandatory Reporting Regulations, firmed and shaped transactions without replacement power from the same balancing authority area and all unbundled REC transactions would not be treated as reducing GHG emissions. Not only does this frustrate the purpose and intent of SBx1 2, which contemplated entities could engage in such transactions as a means of controlling the costs of program compliance, it violates the requirements of State law as discussed below.

B. The Mandatory Reporting Regulation Contradicts the Legislative Intent of the RPS Program

ARB's treatment of out-of-state energy contradicts the legislative intent of the RPS program, which plainly recognizes the environmental benefits of imported generation and RECs.[10]

Under Section 399.12(f)(1) and (2) of the current RPS, so long as the retail seller complies with CEC delivery requirements and other rules surrounding RPS eligibility, that electricity imported to California will be counted as renewable. Section 399.12 defines a "Renewable energy credit" as:

"[A] certificate of proof associated with the generation of electricity from an eligible renewable energy resource, issued through the accounting system established by the Energy Commission pursuant to

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[9] Unlike SB X1 2, the MRR does not contain any grandfather clauses.

[10] The State Legislature's intent that the requirements codified in §399.12 help achieve the GHG emissions reduction and RPS program goals is apparent upon reading §399.11 (Legislative Findings and Declarations), which states in part:

> "In order to attain a target of generating 20 percent of total retail sales of electricity in California from eligible renewable energy resources by December 31, 2010 . . . it is the intent of the Legislature that the commission and the State Energy Resources Conservation and Development Commission implement the California Renewables Portfolio Standard Program described in this article"

and

> "The development of eligible renewable energy resources and the delivery of the electricity generated by those resources to customers in California may ameliorate air quality problems throughout the state and improve public health by reducing the burning of fossil fuels and the associated environmental impacts and by reducing in-state fossil fuel consumption."

Pub. Util. Code §399.11(a), (c).

Section 399.13, that one unit of electricity was generated and delivered by an eligible renewable energy resource."[11]

Furthermore, the statute expressly recognizes both the renewable and the environmental attributes of a REC:

> "Renewable energy credit" includes all renewable and environmental attributes associated with the production of electricity from the eligible renewable energy resource . . ."[12]

Implementation of SB x1 2, the imminent successor to current statutory RPS law, will lead to modifications to the RPS program.[13] It is clear, as noted above, that the new legislation treats electricity imported to California as renewable, provided that delivery requirements and other rules surrounding RPS eligibility are met.[14] Indeed, SBx1 2 goes further by allowing unbundled RECs to qualify in meeting RPS requirements. SB x1 2 incorporates the current RPS program's definition of RECs[15] and, also like the current RPS program, recognizes all renewable and environmental attributes attributed to RECs.[16] Indeed, the Legislature prefaces that SB x1 2 is designed to help California meet its "climate change goals by reducing emissions of greenhouse gases associated with electrical generation."[17]

Definition 239 in Section 95802 of the Cap-and-Trade regulation, added in the 15-day modifications, uses the exact same definition of RECs as Section 399.12 and SB x1 2.[18] The definition references Section 399.12 to acknowledge that "a REC includes all renewable and environmental attributes associated with the production of electricity from an eligible renewable energy resource."[19] Despite these efforts at consistency, the modified Cap-and-Trade Regulation fails to recognize the GHG emission reducing attributes of rebundled energy outside the same balancing authority or any rebundled energy of non-variable renewable resources.[20] This refusal to recognize the zero GHG attribute of some RECs directly conflicts with the state's statutory scheme and legislative intent.

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[11] Pub. Util. Code §399.12(f)(1) (2010), *renumbered as* Pub. Util. Code §399.12(e)(1) (2011).

[12] Pub. Util. Code §399.12(f)(2) (2010), *renumbered as* Pub. Util. Code §399.12(e)(2) (2011).

[13] The CPUC has initiated a rulemaking proceeding, R.11-05-055, to implement SB x1 2.

[14] SB X1 2, Sec. 22 (amending §399.16) adds caps for certain types of energy, but does not restrict their qualification as eligible energy. The specifics of this section still must be clarified.

[15] SB X1 2, Sec. 14 (amending §399.12)

[16] SB X1 2, Sec. 14 (amending §399.12)

[17] SB X1 2, Sec. 13 (amending §399.11).

[18] MRR, Article 5, 95802(a)(239). The Section defines "Renewable Energy Credit" or "REC" as:
"a certificate of proof, issued through the accounting system established by the California Energy Commission pursuant to Public Utilities Code Section 399.13, that one megawatt hour of electricity was generated and delivered by an eligible renewable energy resource. As specified in Public Utilities Code Section 399.12, Subdivision (g)(2), a REC includes all renewable and environmental attributes associated with the production of electricity from an eligible renewable energy resource . . ."

[19] MRR, Article 5, §95802(a)(239) (definition of REC).

[20] Examples of non-variable renewable energy would include baseload biomass and geothermal energy

When a statute confers upon a state agency the authority to adopt regulations to implement, interpret, make specific or otherwise carry out its provisions, the agency's regulations must be consistent, not in conflict, with the statute, and be reasonably necessary to effectuate its purpose."[21] The task of the reviewing court in such a case "is to decide whether the agency reasonably interpreted the legislative mandate."[22] While ARB is granted administrative deference when it is engaged in rulemaking, which requires a high degree of technical skill and expertise, it is never granted discretion to promulgate a regulation that is inconsistent with the governing statute.[23]

The cap-and-trade and mandatory reporting regulations do not deserve any administrative deference. First, ARB is internally inconsistent within the regulation when it states in definition 239 of Section 95802 that all renewable and environmental attributes count towards a REC, but then refuses to recognize those attributes for certain RECs in the definition of replacement electricity, definition 237.

Second, the cap-and-trade and mandatory reporting regulations contradict the California Legislature's clearly enunciated approach toward climate change controls. The legislative intent to recognize the environmental attributes of all RECs is explicitly stated in Section 399.12 and SB x1 2. Furthermore, ARB's own recognition of this principle is evident in its use of the same language, its reference back to Section 399.12, as well as its own proposed Renewable Electricity Standard.[24] Therefore, ARB's refusal to recognize the GHG emissions reduction benefits of unbundled RECs when rebundled energy is outside the balancing authority contradicts the legislative scheme.

Third, ARB's interpretation of which RECs receive GHG zero emissions treatment is not reasonable. By refusing to recognize the environmental attributes of out-of-state renewable energy with replacement electricity outside a balancing authority or unbundled RECs, the regulation implies that GHG emission reductions performed outside of California are inferior to reductions performed in-state or in close proximity to California's borders. Such reasoning is factually incorrect and fails to understand that reducing GHG emissions anywhere in the WECC benefits California.

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[21] *County of San Diego v. State of California*, 15 Cal. 4th 68, 100 (1997) (citing Cal. Gov. Code, § 11374); *Mooney v. Pickett*, 4 Cal.3d 669, 679 (1971) (same).

[22] *Id*.

[23] *Ont. Cmty. Found. v. State Bd. of Equalization*, 35 Cal. 3d 811, 816 (1984) (citing *Credit Ins. Gen. Agents Assn. v. Payne*, 16 Cal.3d 651, 657 (1976)).

[24] ARB's Renewable Electricity Standard, tentatively adopted in September, 2010, recognized the GHG reduction benefits of a 33% renewable standard and adopted a standard that treated as qualifying not only projects with energy delivered to the State, but also "An eligible renewable energy resource that meets all requirements of California's RPS program, excluding electricity delivery requirements, as determined by ARB." Thus, the ARB's own adopted rules would have treated unbundled RECs as meeting its Renewable Energy Standard and, accordingly, contributing to GHG reductions. The ARB order explicitly directed staff to coordinate the use of RECs with the CPUC's TREC decision. However, that TREC decision was itself superseded by SBx1 2, which clearly defines the types of RECs that meet the RPS program's objectives, including its GHG reduction objectives. Under the RES, an out of state renewable, whether firmed and shaped, directly delivered, or unbundled, would count toward the RES requirements. Since those requirements' sole purpose was to support AB32 requirements, those transactions should necessarily be treated as reducing GHG under the Cap and Trade and MRR rules.

For all these reasons, the MRR's refusal to convey zero GHG emissions treatment for rebundled energy outside the same balancing authority for variable renewable energy and for all non-variable renewable energy is unreasonable and contradicts current (and future) statutory law and legislative intent.

C. Proposed Changes to the 15-day Modifications

The ARB proposed 15-day modifications of the cap-and-trade regulation are flawed by 1) allowing replacement power only for variable renewable resources, and 2) requiring the replacement power to be from the same balancing authority. While ARB may think that its solution to require the replacement power to be from the same balancing area solves the double-counting issue related to linked jurisdictions, it does not because state boundaries and balancing authority boundaries are not the same. Bonneville Power Authority Transmission (BPAT) and PacifiCorp East cover multiple states, so it is unclear how replacement power from Utah for wind power from Wyoming or replacement power from Oregon for hydroelectric power from Washington avoids double counting issues when linking with other states takes place. The mismatch is also evident in that renewable resources in northern Idaho in BPAT would receive zero GHG attribute if replacement power is from southern Oregon (also in BPAT), while not receiving the zero GHG attribute if replacement power from the same state but not the same Balancing Authority (Idaho Power Company Balancing Authority area). The potential problems of double-counting should not drive the ARB cap-and-trade regulation to conflict to State law; double-counting can be addressed at the time of linking. If the requirement is for tracking purposes, it is unclear how replacement power from the same balancing area is any easier to track than power from any other balancing authority. The WREGIS system already exists to track RPS-eligible renewable energy and replacement electricity throughout the WECC.

Further, the ARB proposed change provides significant market power in the many small balancing authorities in the WECC. In those small balancing authorities, most of the resources are controlled by a single entity, so that replacement energy would have to come from a single owner of fossil resources.

There are three workable changes ARB should consider to comply with State law concerning renewables and to be consistent with the Scoping Plan that assigns GHG reductions to <u>all</u> renewable energy. In addition, the MRR needs conforming revisions, which we have provided in our comments on the MRR.

First, the <u>best alternative would be to eliminate the requirements</u> that 1) replacement electricity apply only to variable renewable resources and instead apply to all renewable resources, and 2) replacement electricity be from the same balancing authority as the renewable resource.

The limitation to only variable renewable resources ignores the operation of the western electricity grid where there can be transmission constraints even on baseload renewable electricity such as electricity from biomass or geothermal facilities. There is nothing in the RPS program that discriminates against non-variable, baseload renewable resources and no reason for ARB to diminish their GHG reduction value. Eliminating the requirement that replacement power be from the same balancing authority and instead referencing the RPS regulation would eliminate the inconsistency between the cap-and-trade regulation and the RPS legislation. Replacement electricity should be allowed for all renewable energy developed pursuant to the State's 33 percent renewable program.

This approach would allow for the rebundling of RECs with any imports already approved by the CEC and CPUC. In addition, it would allow for future projects, including transactions using unbundled RECs, that may be consistent with the restrictions of the RPS program as modified by SB x1 2. This would result in replacement electricity being treated as having zero emissions, to reflect the fact that the underlying renewable is resulting in a backing down of emissions elsewhere in the region. Commensurate with this structure, renewable power that is sold without RECs becomes "null power" and like unspecified power imported to California should be assigned a default GHG emission rate for compliance obligation purposes. This approach would be consistent with the contractual terms of existing contracts, Section 399.12, and expectations of the parties who signed the contracts. All the requisite data is already tracked in the WREGIS tracking system. While this approach may create issues for linkage with other states, it would be no different than dealing with existing long-term contracts that do not contemplate a GHG cost; the issue can be resolved as part of the linking process. Below is suggested language for the cap-and-trade regulation to effectuate this approach.

Modification of Definition of Replacement Electricity in Section 95802

> Section 95802 (237) "Replacement electricity" means electricity delivered to a first point of delivery in California **<u>in accordance with State Renewable Portfolio Standards</u>** to replace electricity from ~~variable~~ **<u>RPS-eligible</u>** renewable resources in order to meet hourly load requirements. The electricity generated by the ~~variable~~ renewable energy facility and purchased by the first deliverer is not required to meet direct delivery requirements. ~~The physical location of the variable renewable energy facility busbar and the first point of receipt on the NERC E-tag for the replacement electricity must be located in the same balancing authority area.~~

A second approach would be to "grandfather" contracts entered into prior to the start of the cap-and-trade program and add more flexibility to ARB's approach requiring replacement electricity to be from the same balancing authority. The latter provision would account for the fact that over one-third of balancing authorities in the WECC outside of California are small, single entity balancing authorities. With grandfathering, the regulation would state that for contracts entered into before the start of the cap-and-trade program, replacement power could be used consistent with CEC and CPUC approved rebundling. Such contracts would be supplied to ARB and for that list of contracts, the replacement power would not be required to be from the same balancing authority, but from a source or sources approved by the CEC and/or CPUC. For grandfathered contracts, this would result in replacement electricity being treated as having zero emissions, to reflect the fact that the underlying renewable is resulting in a backing down of emissions elsewhere in the region. The electricity from the renewable resource without the green attributes would be assigned the default rate and could not be used as a specified zero GHG resource. While this approach would at least protect consumers from being harmed by rules that reduce the value of existing contracts, it would still potentially add unnecessary costs to the state's electric consumers since it would effectively eliminate the future ability to develop certain out of state renewable energy even though it would comply with the RPS and reduce overall GHG emissions.

Accordingly, this second approach is a "second-best" solution. Proposed language to change the 15-day modification is shown below:

Modification of Definition of Replacement Electricity in Section 95802

> Section 95802 (237) "Replacement electricity" means electricity delivered to a first point of delivery in California to replace electricity from ~~variable~~ **RPS-eligible** renewable resources in order to meet hourly load requirements. The electricity generated by the ~~variable~~ renewable energy facility and purchased by the first deliverer is not required to meet direct delivery requirements. The physical location of the ~~variable~~ renewable energy facility busbar and the first point of receipt on the NERC E-tag for the replacement electricity must be located in the same balancing authority area**, or if a balancing authority is small, an adjacent balancing authority, for RPS contracts signed after the start of the cap-and-trade program. For RPS contracts signed prior to the start of the cap-and-trade program, replacement electricity must be delivered to California in accordance with the State Renewable Portfolio Standards[25].**

A third approach would be an adjustment to other elements of the cap-and-trade regulation and would not require significant changes to the definition of replacement electricity except to deal with small balancing authorities. The approach would adjust the annual allowance budgets for Calendar Years 2013-2020 in Section 95841 to account for the zero GHG renewable resources that are not being counted as zero GHG under the cap-and-trade program. In the cap-and-trade regulation adopted by the ARB in December 2010, the annual allowance budgets were dramatically reduced to account for emissions in covered sectors that were not covered by the cap-and-trade regulation. This approach would reverse the process and account for reduced GHG emissions of the out-of-state renewables that were not being counted in the cap-and-trade program. The adjustment to the program cap would take place annually based on the prior year energy production by the renewable resources that are not being counted as zero GHG.

The second part would be to provide the allowances to the electricity importer for that replacement electricity that is not counted as zero GHG under the cap-and-trade program. Once the prior year production of renewable energy not counted as zero GHG is determined, ARB would place the allowances into the importers' holding accounts. This approach would be similar to one approach ARB has recommended for long-term contracts with no ability to pass on GHG costs. ARB recommended that generators in that situation receive free allowances or that the sellers and buyers renegotiate the contract terms to consider GHG costs. This approach would increase the program cap for known renewable energy contracts entered into pursuant to the RPS and provide the free allowances for those contracts. For example, if the SDG&E wind contracts produced 1.2 million MWhs in 2013 at the default emission factor, 0.428 MT/MWh, ARB would place 0.5136 MMT into SDG&E's holding account in 2014 before the compliance surrender date of November 1, 2014 for 2013 compliance

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[25] SEu expects that ARB would create a list of balancing authorities it considered "small."

obligation. This approach is also "second best" since it is complicated and relies on lagged data. Proposed changes to the cap-and-trade regulation include the following:

Modify Definition of Replacement Electricity in Section 95802

Section 95802 Definition (237) "Replacement electricity" means electricity delivered to a first point of delivery in California to replace electricity from ~~variable~~ **RPS-eligible** renewable resources in order to meet hourly load requirements. The electricity generated by the ~~variable~~ renewable energy facility and purchased by the first deliverer is not required to meet direct delivery requirements. The physical location of the ~~variable~~ renewable energy facility busbar and the first point of receipt on the NERC E-tag for the replacement electricity must be located in the same balancing authority area**, or if the balancing authority is small, an adjacent balancing authority.**

Add to Section 95841 after table 6-1

The annual allowance budgets shown in Table 6-1 will be adjusted upward in each compliance year for the energy from renewable resources developed and approved pursuant to the State's RPS program that do not have replacement electricity meeting the requirements of section 95802 and do not affect the compliance obligations in section 95852. The amount of energy will be based on the positive or qualified positive emissions data verification statement for the year for which the compliance obligation is calculated.

Modify Section 95780

(f) Allocation to Electricity Importers for RPS-eligible Renewable Energy Requiring Allowance Surrender

(1) The Executive Officer will place an annual individual allocation in the holding account of each eligible entity on or before the surrender dates for compliance for each calendar year 2013-2020.

(2) The total amount of allowances shall be calculated consistent with the adjustment to the program cap in section 95841

(**g**~~f~~) Auction Proceeds for AB 32 Statutory Objectives. All remaining allowances not allocated for uses specified in sections 95870(a) through (**f**~~e~~) will be designated for sale at auction. The proceeds from the sale of these allowances will be deposited into the Air Pollution Control Fund and will be available for appropriation by the Legislature for the purposes designated in California Health and Safety Code Sections 38500 *et seq*.

II. Key Issue 2 - Resource Shuffling in Cap-and-Trade Regulation

SEu share ARB's concern for the integrity of the cap-and-trade program and the desire to prohibit resource shuffling. However, as written, the resource shuffling provisions are vague and overly broad, contradict CPUC requirements for utilities to undertake least cost dispatch, violate the intent of the cap-and-trade regulation, and create significant Commerce Clause issues. Additionally, the new rules on "resource shuffling" would define conduct as "resource shuffling" even if the conduct was performed innocently. At the same time, the rules would define this innocently-performed conduct as "fraud" – "Resource shuffling is prohibited, is a violation of this article and is a form of fraud."[26] However, California law is well-settled, that to constitute fraud, conduct must be intentional, with the specific intent to induce reliance.[27] Innocent conduct can never be fraud because it lacks the specific intent required.

A few examples illustrate that the current definition is deficient.

- First, all three California IOUs are obligated to dispatch their resources in the most efficient manner under CPUC Least-Cost Dispatch requirements. In accordance with these rules, a California utility that has a long-term contract with a coal unit in Arizona, for instance, must make decisions daily and hourly as to whether this unit should be economically dispatched. As such, if, due to transmission constraints, the electricity cannot be delivered to California but it is economic to deliver the electricity to Phoenix, the IOU is obligated to sell the power in Arizona. Under the current definition, it would be considered Resource Shuffling since there are no exceptions to the definition for operational constraints and economic dispatch.

- Second, take the situation of an Energy Service Provider (ESP) that had a rolling annual coal contract that began before 2009 where it took delivery of the electricity out-of-state and imported the power to its customers. In 2013, the ESP does not renew the coal contract and switches to importing lower cost natural gas (because of the carbon cost from the cap-and-trade program). It would be Resource Shuffling by the current definition for that ESP to buy anything but coal. The imported electricity "previously served load in California" and would no longer be serving California, but it would not be covered by the Emission Performance Standard because it was less than a five year contract. Under the draft rules the ESP would be guilty of "fraud" (whether or not there was a specific intent to defraud) and subject to ARB enforcement as well as potential California criminal (for perjury) and civil penalties unless it continued to buy higher cost and higher emitting coal.

- Third, take the situation of a small gas-fired generator in Nevada (<25,000 MT) that decides to sell into the CAISO energy market to obtain the higher prices. Under the current definition such transactions would be considered Resource Shuffling and subject the seller to ARB enforcement as well

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[26] MRR Article 5, §95852(b)(1).

[27] The California Supreme Court defines fraud as "(1) a misrepresentation, (2) with knowledge of its falsity, (3) with the intent to induce another's reliance on the misrepresentation, (4) justifiable reliance, and (5) resulting damage." *Conroy v. Regents of University of California*, 45 Cal. 4th 1244, 1255 (2009).

as California criminal and civil penalties. The small generator did not "historically serve" California per the definition in the MRR and there are higher emissions outside of California (since the Resource Shuffling definition does specify that the electricity with higher emissions has to be from the same provider). Labeling this transaction "fraud" would create Commerce Clause problems by treating electricity importers differently than California entities.

If viewed properly, Resource Shuffling is a reporting issue and could exist where there is an intentional attempt to evade the cap-and-trade rules leading to the underreporting of GHG emissions. For ARB to properly deal with Resource Shuffling, the definition of resource shuffling needs to be defined more precisely to avoid labeling legitimate transactions as resource shuffling.[28] While restrictions may be needed, it is important to draft such restrictions in a manner that does not treat legitimate electricity market transactions as a crime. The definition of Resource Shuffling found in Section 95802(a)(245) and the provisions of Section 95852(b)(1) must be changed in the manner described below. In addition, because such extensive changes are needed, we recommend that ARB follow-up with a stakeholder process, including a workshop and additional comments to further refine the rules to meet the disparate concerns of market participants.

Proper reporting needs to be clearly articulated in Section 95111 of the MRR to allow entities to avoid claims of resource shuffling. Recommended changes to the MRR are described in the SEu comments on the MRR; here, only changes to the cap-and-trade regulation are addressed.

The first change required is to modify the definition of resource shuffling to narrow it to three types of resource shuffling: 1) importing power from a low emitting resource in place of a higher emitting resource from the supplier's same portfolio of resources; 2) selling high emitting power from a facility owned or under long-term contract out-of-state and replacing it with low emitting or unspecified imported power; and 3) moving energy from high emitting specified resources around the WECC so that it origins cannot be traced and it is assigned the default emissions factor. A fourth type of transaction could be resource shuffling but cannot be prevented due to Commerce Clause issues: A single generation facility that is low emitting will gain a benefit by selling into the California market where it previously had not, while a coal facility may not economically dispatch into California because of its high GHG cost. This type of economic shuffling, and the resulting leakage, cannot be prevented due to the Commerce Clause[29].

The Resource Shuffling definition should also make it clear that the importer of the electricity and not the buyer is the sole entity that is engaging in resource shuffling. Buyers of electricity, or facilitators of

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[28] It is noted that ARB removed much of the language in the MRR that would reduce the potential for resource shuffling including specific provisions regarding using the default emissions factor for hydro and nuclear energy from existing sources and monitoring high GHG resources either owned or under long-term contract.

[29] The Commerce Clause prohibits states from unjustifiably discriminating against or burdening the interstate flow of articles of commerce. *Or. Waste Sys., Inc. v. Dep't of Envtl. Quality*, 511 U.S. 93, 98 (1994) (citing U.S. Const. Art. I, § 8, cl. 3). "[D]iscrimination simply means differential treatment of in-state and out-of-state economic interests that benefits the former and burdens the latter." *Id.* at 99. The MRR, as currently drafted, would treat certain out-of-state economic interests negatively and thus, burden interstate commerce.

electricity transactions such as the CAISO, should not have to investigate every import transaction to see if the electricity source is properly reported. To do otherwise would destroy markets for electricity and require all transactions to be bilateral with specified resources to avoid transactions being deemed fraudulent by ARB. Additionally, the definition needs to be clarified to make it clear that resource shuffling only occurs as a result of intentionally underreporting.

Finally, no attestations should be required since resource shuffling properly defined would be a misreporting of emissions and subject to enforcement pursuant to the MRR provisions on inaccurate reporting as well as Section 96014(c) of the Cap-and-Trade Regulation. The attestations serve no useful purpose, but do tend to raise the specter that perfectly valid conduct might be treated as inconsistent with the attestation. Further, as resource shuffling is currently defined in the 15-day modifications, it is not a fact, but a legal opinion, and therefore cannot be attested to. For example any sale of electricity from a facility other than coal existing in the WECC that did not deliver electricity to California in 2009 may be legally considered by the Cap-and-Trade Regulation as engaging in resource shuffling. A single facility, on the other hand, may rightly believe it is impossible for it to "resource shuffle" if it has no other resources.

The following offers one way of potentially narrowing the definition of "resource shuffling," but it is not the only way of dealing with the issue. For example, restoration of the language regarding hydroelectricity, nuclear power, and high-emitting resources that was deleted in the 15-day modifications could also go a long way toward correcting part of the problem.

The definition of resource shuffling in Section 95802 should be modified as follows:

Modify Section 95802

> Section 95802 (245) "Resource Shuffling" means ~~any plan, scheme, or artifice to receive credit based on emissions reductions that have not occurred, involving the delivery of electricity to the California grid, for which~~ **<u>intentionally underreporting emissions of imported electricity in any of the following ways and does not include transactions entered into for operational purposes as demonstrated according to the provisions in section 95111(b)(2) of the MRR</u>:**
>
> (A) An emission factor below the default emission factor is reported pursuant to MRR for a generation ~~source~~ **<u>facility or unit of an asset-controlling supplier</u>** that has not historically served California load (excluding new or expanded **<u>facility or unit</u>** capacity). And, during the same interval(s), electricity **<u>from the same asset-controlling supplier</u>** with higher emissions was delivered to serve load located outside California and in a jurisdiction that is not linked with California's Cap-and-Trade Program; or
>
> (B) The default emission factor or a lower emissions factor is reported pursuant to MRR, for electricity that replaces electricity with an emissions factor higher than the default emission factor that ~~previously~~ serve<u>s</u>~~d~~ load in California **<u>pursuant to an ownership interest or long-term contract</u>**; except when the ~~replaced~~ **<u>higher emitting</u>** electricity no longer serves California

load as a result of compliance with the Emission Performance Standards adopted by the California Energy Commission and the California Public Utilities Commission pursuant to Senate Bill 1368 (Perata, Chapter 598, Statutes of 2006) **; or**

(C) Specified electricity with an emissions factor higher than the default emission factor is knowingly reported by the electricity importer as unspecified electricity.

Section 95852(b)(1) should be modified to eliminate the reference to fraud and to eliminate the attestation.

Modify Section 95852(b)(1)

Section 95852(b)(1) Resource shuffling is prohibited, is a violation of this article ~~and is a form of fraud~~. ~~ARB will not accept a claim that emissions attributed to electricity delivered to the California grid are at or below the default emissions factor for unspecified electricity specified pursuant to MRR section 95111 if that delivery involves resource shuffling. The following attestations must be submitted to ARB annually in writing, by certified mail only:~~
~~(A) "I certify under penalty of perjury of the laws of the State of California that [facility or company name] has not engaged in the activity of resource shuffling to reduce compliance obligation for emissions, based on emission reductions that have not occurred."~~

~~(B) "I understand I am participating in the Cap-and-Trade Program under title 17, California Code of Regulations, article 5, and by doing so, I am now subject to all regulatory requirements and enforcement mechanisms of this program and subject myself to the jurisdiction of California as the exclusive venue to resolve."~~

III. Key Issue 3 - Allocation of Auction Revenues

A. Section 95892(d)(3) is Inconsistent with ARB Distribution of Allowances

ARB should delete Sections 95892(d)(3)(B) and (d)(3)(C), which purport to establish utility rate design, since they are at odds with ARB's allocation method across utilities described in detail in Appendix A to the 15-day Modifications to the cap-and-trade regulation, and since they attempt to usurp the PUC's exclusive authority governing the setting of utility retail rates.

These two sub-sections of the cap-and-trade regulation were adopted at a time when it was still unclear whether ARB would base the allocation to individual electric utilities on a transition to a sales-based approach proposed by the CPUC and CEC or a method based on compliance burden. A sales-based approach would provide a price signal, while a compliance burden approach would not. Since ARB adopted an allocation in Section 95892 Table 9-3 based on compliance burden, it should allow the

CPUC the same flexibility to adopt a similar approach, if it chooses, in rate-making instead of keeping the outdated language in Sections 95892(d)(3)(B) and 95892(d)(3)(C).

In Appendix A to the 15-day Modifications to the Cap-and-Trade regulation, ARB states "A central principle of the allowance allocation to the electricity sector is the incorporation of customer cost burden" and "As a matter of policy the approach to allocating allowances to the electric sector has been to ensure that each utilities allocation is at least equal to their customers' total expected cost burden in each year." If allocation based on compliance burden is the ARB policy and is the central principle relied on to allocate allowances between customers of different electric distribution utilities, it is unclear why ARB would not want to allow the CPUC to follow the same principle in its rate-making, if it so chooses. Sections 95892(d)(3)(B) and 95892(d)(3)(C) should be deleted to allow the CPUC to perform its rate-making function and to have the option to follow ARB principles and policy in distributing the cost burden between customers of the same utility.

B. The California Constitution and Public Utilities Code Have Exclusive Regulatory Authority to Fix and Design Rates

ARB has authority to design its cap-and-trade regulation to include distribution of GHG emissions allowances pursuant to AB 32. ARB also has the ability to restrict the use of allowances in ways that may cause the market to not function properly such as requiring that the allowances be auctioned and not used directly for compliance so as to increase the liquidity of the market. And ARB has the ability to direct how the use of allowance revenues should be allocated between different LSEs who may not get a direct allocation (ESPs and CCAs). However, AB 32 stops short of granting ARB authority to direct how electric utilities subject to the CPUC jurisdiction should use revenues from the auctioning of GHG emissions allowances as it is the CPUC that has the authority over rate-setting functions.

The California Constitution provides that "[a] city, county or other public body may not regulate matters over which the Legislature grants regulatory power to the Commission." [30] Accordingly, as to matters over which the CPUC has been granted regulatory power, the CPUC's jurisdiction is exclusive.31 The purpose of this exclusivity is to promote uniformity throughout the State and eliminate conflicting regulations.[32] Pursuant to the California Constitution, the Commission has general regulatory authority to fix rates and assure that rates and allocation of costs are just and reasonable, and nondiscriminatory.[33]

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[30] Cal. Const., art. XII, § 8.

[31] *City of Anaheim v. Pacific Bell Telephone Company,* 119 Cal. App. 4th 838, 842 (2004), *Southern Cal. Gas Co. v. City of Vernon*, 41 Cal. App. 4th 209, 215 (1995).

[32] *City of Vernon,* 41 Cal. App. 4th at 215.

[33] *See generally,* Cal. Const., art. XII, § 5. *See Pacific Bell Wireless, LLC v. Pub. Utils. Comm'n of State of Cal.,* 140 Cal.App.4th 718, 736 (2006) ("The Constitution confers broad authority on the commission to regulate utilities, including the power to fix rates . . .").

Likewise, the Public Utilities Code grants the Commission specific authority to fix and design rates.[34] Accordingly, the CPUC's jurisdiction over rate-setting and rate design is exclusive.

AB 32 requires ARB to "consult" with the CPUC in the development of the regulations as they affect electricity and natural gas providers "in order to minimize duplicative or inconsistent regulatory requirements."[35] The language in Sections 95892(d)(3)(B) and 95892(d)(3)(C) creates a risk of inconsistent regulatory requirements, should the CPUC choose to take a different approach in the GHG OIR, R.11-03-012. And the CPUC certainly has the authority to take a different approach, given the CPUC's exclusive jurisdiction over these matters and the express language of AB 32, which makes clear that nothing in AB 32 "affects the authority of the Public Utilities Commission."[36]

The Office of Administrative Law ("OAL") may strike down Sections 95892(d)(3)(B) and 95892(d)(3)(C) of the cap-and-trade regulation pursuant to the Administrative Procedure Act (Cal. Gov. Code 11340 et seq.). The OAL must review the regulation for, among other criteria, consistency.37 "Consistency" is defined in the Administrative Procedure Act as "being in harmony with, and not in conflict with or contradictory to, existing statutes, court decisions, or other provisions of law."[38] In making this determination, the OAL would consider whether the regulation is within the scope of ARB's authority.[39] Accordingly, since language in Sections 95892(d)(3)(B) and 95892(d)(3)(C) is in conflict with AB 32, in that the language expands the scope of that statute's authority, and the language conflicts with the California Constitution and the Public Utilities Code, which, read together, convey exclusive rate-making jurisdiction to the CPUC, the OAL may strike down the language on its own initiative. To avoid this outcome, ARB should strike Sections 95892(d)(3)(B) and 95892(d)(3)(C) of its own accord.

C. Proposed Changes to Section 95892(d)(3)

To be consistent with ARB's demonstrated intent to allocate allowance revenue to assist in mitigating compliance burden, to recognize Section 95892 (d)(3) Sections (B) and (C) go beyond ARB's authority, and to avoid legal challenges, ARB should make the following changes to 95892(d)(3):

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[34] Pub. Util. Code, § 451 (providing for just and reasonable rates, charges and services), 453 (prohibiting the granting of preference or advantage to any corporation or person), §§ 453.5, 792.5 (guiding the Commission's use of refunds, rebates and balancing accounts), and § 701 (providing the Commission with a broad authority to do all things necessary in carrying out its regulatory duties, including ensuring just and reasonable allocation of costs and nondiscriminatory treatment). *See also Schell v. Southern Cal. Edison Co.,* 204 Cal. App. 3d 1039, 1045 (1988) (holding that the issue of what rate to charge certain residential customers was clearly within the exclusive purview of the CPUC as part of its "continuing jurisdiction over rate making and rate regulation in provision of baseline service to residential customers of the electric and gas corporations").
[35] Cal. Health and Safety Code § 38562(f).
[36] Cal. Health and Safety Code § 38593(a).
[37] *Id.* § **11349**.1(a)(4).
[38] *Id.* § **11349(d)**.
[39] *Samantha C. v. State Dept. of Developmental Services*, 185 Cal.App.4th 1462 1481-82 (2010).

Modify Section 95892(d)(3)

(3) Auction proceeds obtained by an electrical distribution utility shall be used exclusively for the benefit of retail ratepayers of each electrical distribution utility, consistent with the goals of AB 32, and may not be used for the benefit of entities or persons other than such ratepayers.
(A) Investor owned utilities shall ensure equal treatment of their own customers and customers of electricity service providers and community choice aggregators.
~~(B) To the extent that an electrical distribution utility uses auction proceeds to provide ratepayer rebates, it shall provide such rebates with regard to the fixed portion of ratepayers' bills or as a separate fixed credit or rebate.~~
~~(C) To the extent that an electrical distribution utility uses auction proceeds to provide ratepayer rebates, these rebates shall not be based solely on the quantity of electricity delivered to ratepayers from any period after January 1, 2012.~~

IV. Key Issue 4 – Allowance Price Containment Reserve Depletion

SEu supports ARB's inclusion of the Allowance Price Containment Reserve ("Reserve") in the Cap-and-Trade Regulation as an essential tool to address the potential for price spikes and a market meltdown that would overflow into electricity markets. Because a robust Reserve is necessary to ensure the long-term success of the Cap-and-Trade program, ARB should establish a procedure in the Cap-and-Trade regulation to replenish the reserve should it become depleted. With language in the regulation identifying the triggering event and action to be taken, the market will have assurance that a timely remedy will be in place. The approach outlined below is only one of several alternatives to accomplish the market stabilization goal, but would ensure the Cap-and-Trade market will provide additional emissions reductions at a fair price.

Modify Section 95913

Section 95913 (c) Timing, Eligible Participants, ~~and~~ Limitations, **and Reserve Replenishment**.

Add: Section 95913(c)(5) Reserve Replenishment.

(A) When the Reserve is fully depleted, the Executive Officer shall make available for purchase to each covered entity or opt-in covered entity sufficient allowances to allow that covered entity or opt-in covered entity to fully satisfy any remaining compliance obligation at the allowance price of the third tier of the Reserve at the time the Reserve is fully depleted.
(B) Only Covered Entities with a Holding Account balance of zero shall be able to purchase such allowances.
(C) Purchases of such allowances shall be transferred directly into a Covered Entity's Compliance Account.

<u>(D) Within 3 months of the time the Reserve is fully depleted, the Executive Officer and Market Monitor shall make a recommendation to the Board on program modifications necessary to replenish the Reserve.</u>

Section by Section Comments

Section 95802. Definitions

Comment: ARB has failed to explain or justify its establishing a forestry offset buffer instead of a general offset buffer. The following change is to implement an offset buffer in general rather than a specific forestry offset buffer. The following definition is needed to implement an offset buffer as described more fully in comments on Section 95983 below.

Modify and reorder

> "~~Forest~~ **<u>Offset</u>** Buffer Account" means a holding account for ARB offset credits issued to ~~forest~~ **<u>ARB-approved</u>** offset projects. It is used as a general insurance mechanism against unintentional reversals, for all ~~forest~~ offset projects listed under a Compliance Offset Protocol.

Comment: The definition of power contract should match the definition in the MRR and should be used throughout the cap-and-trade regulation in the definition (258) specified sources.

Add

> **<u>(xxx) "Power contract" means a written document arranging for the procurement of electricity. Power contracts may be, but are not limited to, power purchase agreements, enabling agreements, and tariff provisions.</u>**

Section 95831(b) Account Types

Comment: In this Cap-and-Trade regulation ARB has established a forestry offset buffer account. It is reasonable that ARB should expand the forestry offset buffer account concept into a general Offset Buffer account. The following change is to implement an offset buffer in general rather than a specific forestry offset buffer. The following change is needed to implement an offset buffer described more fully in comments on Section 95983 below.

Modify Section 95831(b)(5)

> (5) A holding account to be known as the ~~Forest~~ **<u>Offset</u>** Buffer Account:
> (A) Into which ARB will place ARB offset credits pursuant to section 95983(a); and

(B) From which ARB may retire ARB offset credits pursuant to sections 95983(d)(b)(2), (c)(3), and (c)(4) and place them into to the Retirement Holding Account.

Section 95852. Emission Categories Used to Calculate Compliance Obligations

Comment: Sections 95852(b)(2) through 95852(b)(7) of the Cap-and-Trade regulation should not incorporate the language specific to mandatory reporting, but should instead incorporate it by reference. The approach that the regulations have used have created confusion by attempting to paraphrase the MRR, using language different from that used in the MRR, and created internal inconsistency by, on occasion, summarizing the MRR incorrectly -- the language in Section 95852 does not exactly match the MRR. Examples include the formula in Section 95852(b)(7)(C) being different than the formula in Section 95111(b)(5) in leaving out deductions for replacement electricity, and emissions from a specified source with emissions exceeding the default emissions factor are counted in Section 95852(b)(7)(B) at the default emissions rate while being counted at the actual specified emissions rate in Section 95111(b)(2) of the MRR. Section 95852(b) should be changed to incorporate the MRR by reference as much as possible to avoid confusion in compliance obligation. Lastly, Section 95852(b) appears to include sources in California, so a calculation method for in-state resources should be included for *completeness.*

Modify Section 95852 (b)

(2) The following criteria must be met ~~for~~ **by first deliverers of** electricity ~~deliveries~~ to calculate their compliance obligations **for imported electricity from specified facilities or units in jurisdictions that are not approved for linkage pursuant to subarticle 12 and which do not involve replacement electricity**: ~~based on an ARB facility specific emission factor specified pursuant to MRR section 95111 less than the default emission factor for unspecified electricity specified pursuant to MRR section 95111:~~

(A) Electricity deliveries **must meet the requirements of** ~~be reported to ARB pursuant to~~ MRR section 95111**(a)(4)**;

(B) ~~The first deliverer must be the facility operator or have ownership or contract rights to electricity generated by the facility or unit claimed;~~ **Electricity deliveries must meet the requirements of direct delivery of electricity as defined in MRR section 95102(a); and**

(C) First deliverers must ~~report electricity~~ **calculate emissions** from specified sources ~~to ARB using the ARB specified source identification number assigned to the source~~ **in accordance with** ~~pursuant to~~ MRR **section 95111(b)(2).** ~~; and~~

~~(D) If there are other parties within the contract chain of custody, then the original source of generation and quantity of MWhs to be delivered under the original contract must be identified within the entire contract chain. The quantity of electricity delivered, and for~~

~~which an ARB facility specific emission factor specified pursuant to MRR section 95111 is claimed, cannot exceed the original amount under ownership or contract rights reported pursuant to section 95852(b)(2)(A).~~

(3) Replacement electricity that substitutes for electricity from a ~~variable~~ renewable resource qualifies for the ARB specific emission factor ~~specified pursuant to MRR section 95111 of the variable renewable resource~~ under the following conditions:

(A) **<u>Replacement electricity must meet the requirements of MRR section 95111(a)</u>** ~~First deliverers of replacement electricity have a contract, or ownership relationship, with the supplier of the replacement electricity, in addition to a contract with the variable renewable resource~~;

(B) The amount of the reported replacement electricity does not exceed the amount for the reported annual variable renewable resource**<u>; and</u>**

(C) **<u>The r</u>**~~R~~eplacement electricity ~~with an~~ emission factor**<u>s are calculated in accordance with</u>** ~~greater than the default emission factor for unspecified electricity specified pursuant to~~ MRR **<u>sections 95111(b)(1) through 95111(b)(5).</u>** ~~is not eligible to receive an emission factor of zero metric tons CO2e/MWh. For contracts that use replacement electricity for which the emission factor is greater than the default emission factor for unspecified electricity, the difference between the emission factor from the replacement electricity and the default emission factor for unspecified electricity will be used to calculate emissions with a compliance obligation.~~

~~(4) Claims to resources with zero direct emissions, emissions without a compliance obligation, or emissions calculated using a lower emissions factor than the default emissions factor for unspecified electricity specified pursuant to MRR section 95111, including renewable resources other than variable renewable resources must demonstrate, pursuant to MRR, direct delivery of electricity as defined in section 95802.~~

(4~~5~~) Electricity generated from use of biomethane must comply with section 95852.2, and must meet verification requirements for use of biomethane pursuant to MRR.

(5~~6~~) Qualified Exports. Emissions from qualified exports claimed by a first deliverer may be subtracted from the first deliverer's compliance obligation for imported electricity **<u>in accordance with MRR section 95111(b)(5)</u>** only if the electricity **<u>meets the definition of qualified export in MRR section 95102(a).</u>** ~~is exchanged within the same hour and by the same PSE. It is not necessary for the electricity to enter or leave California at the same intertie. Qualified exports shall not result in a negative compliance obligation for any hour.~~

(6~~7~~) The compliance obligation **<u>for first delivers for</u>** ~~(CO2e covered) is calculation based on the~~ emissions from electricity deliveries from jurisdictions that are not approved for linkage pursuant to subarticle 12 **<u>is to be calculated in accordance with MRR section 95111(b)(5</u>**<u>).</u>

~~(A) Emissions which result from specified electricity deliveries (CO2e specified) will be assigned the facility emission factor, determined by ARB, for electricity deliveries meeting the requirements of section 95852(b)(2) through (5);~~

~~1. Specified deliveries meeting the requirements of section 95852(b)(2);~~

~~2. The adjustment for replacement electricity associated with the variable renewable electricity pursuant to section 95852(b)(3);~~

~~3. The specified electricity meeting direct delivery requirements pursuant to section 95852(b)(4); and~~

~~4. The specified electricity generated from the use of biomethane which meets the requirements pursuant to section 95852.2.~~

~~(B) All deliveries of electricity not meeting the requirements of section 95852(b)(2) through (5) will have emissions calculated using the default emission factor for unspecified electricity~~
~~pursuant to section 95111 of MRR (CO2e unspecified).~~

~~(C) Emissions resulting from qualified exports (CO2e qualified exports) will be subtracted from the compliance obligation pursuant to section 95852(b)(6).~~

~~Compliance Obligation in CO2e covered=CO2e specified + CO2e unspecified-CO2e qualified export~~

(7) The compliance obligation for electric generation and cogeneration facilities or units within California for emissions from electricity generated is to be calculated in accordance with MRR section 95112.

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

Comment: ARB added Section 95852 in the 15-day Modifications to describe the emissions subject to a compliance obligation. Section 95853 should reference Section 95852 since not all of the emissions reported may be subject to a compliance obligation. For example, biomass emissions must be reported and verified, but may not lead to a compliance obligation.

Modify

(a)A covered entity that exceeds the threshold in Section 95812 in any of the three data years preceding the start of a compliance period is a covered entity for the entire compliance period. The covered entity's triennial compliance obligation in this situation is calculated as the total of the emissions **calculated in accordance with Section 95852** ~~that received a positive or qualified~~

~~positive emissions data verification statement, or were assigned emissions pursuant to section 95131 of MRR~~ from all data years of the compliance period.

Section 95854. Quantitative Usage Limit on Designated Compliance Instruments – Including Offset Credits

Comment: SDG&E appreciates the change to the offset limit contained in 15-day Modifications to the Cap-and-Trade Program that expanded the offset limit to compliance periods. However, there is no reason to limit the carryover to a compliance period. Allowing the limit to apply cumulatively would provide more flexibility without changing the intent of the regulation to limit the use of offsets to 8 percent of the compliance obligation. Proposed changes to subsection (b) of the regulation are shown below.

Modify

Section 95854(b) The total number of compliance instruments identified in section 95854(a) that each covered entity may surrender to fulfill the entity's compliance obligation ~~for a compliance period~~ must conform to the following limit:
O_O/S must be less than or equal to L_O
In which:
O_O = Total number of compliance instruments identified in section 95854(a) submitted **since January 1, 2013** to fulfill the entity's total compliance obligation ~~for the compliance period~~ **through the current compliance year.**
S = Covered entity's **total** compliance obligation **beginning January 1, 2013 through the current compliance year.**
L_O = Quantitative usage limit on compliance instruments identified in section 95854(a), set at 0.08.

Section 95890. General Provisions for Direct Allocations.

Section 95890 (b) states that in order to be eligible for direct allocations an electrical distribution utility must have "complied with the requirements of MRR" and "obtained a positive or qualified positive emissions data verification statement for the prior year pursuant to MRR." This provision should be removed now that ARB has decided to specify the allocations for electric distribution utilities for each year in Table 9-3 in Section 95892. The purpose of this subsection was to update sales-based allocations with the latest data if the allocations were to transition to a sales-based allocation as recommended by the CPUC and the CEC. The decision in the 15-day modifications to not use sales or emissions as a basis means this subsection is not necessary and should be deleted.

Delete

~~(b) Eligibility Requirements for Electrical Distribution Utilities. An electrical distribution utility shall be eligible for direct allocation of California GHG allowances if it has complied with the requirements of MRR and has obtained a positive or qualified positive emissions data verification statement for the prior year pursuant to MRR.~~

Comment: For the same reasons, Section 95890 (c) should <u>not</u> be deleted. This provision should not be removed until ARB has decided how to allocate allowances to natural gas utilities for the protection of their small customers. Section 95893 is still Reserved for Allocation to Natural Gas Distribution Utilities for Protection of Natural Gas Customers, so when ARB addresses that question it should have this subsection available so as to not limit the potential methods of distributing allowances to individual natural gas utilities.

Do Not Delete

Section 95890<u>**(c) Reserved for Natural Gas Distribution Utilities.**</u>

Section 95892

Comment: If ARB chooses not to make any changes to its cap-and-trade and mandatory reporting regulations regarding replacement electricity as requested in these comments, then Table 9-3 is incorrect since it has as an underlying assumption that all renewable electricity that complies with the State's 33 percent RPS has zero GHG emissions. Under the 15-day modifications, 1.2 million MWhs of wind energy per year that SDG&E has contracted for would have a compliance burden. Under the compliance burden approach outlined in Appendix A to the 15-day modifications, SDG&E should be provided free allowances for this electricity. SDG&E cannot provide proposed modifications to Table 9-3 since it does know what replacement electricity of other electric distribution utilities is not counted as zero GHG electricity.

Section 95983.

Comment: SDG&E has concerns about ARB's "buyer liability" approach to addressing situations in which problems are identified with offset credits after they have been issued. The risk of such post-issuance problems is small because of the rigor of the ARB offset regulations; however, any policy under which already-issued offset credits carry a risk of invalidation will prevent the development of a well-functioning market in offsets. An unworkable offsets program that results in substantially less offsets being developed could have adverse consequences for the AB 32 program, as shown by ARB's own March 24, 2010 economic analysis. In order to develop a well functioning offset market, buyer liability has to be eliminated. One way is to use the structure of the forestry offset buffer, but expand it to be a general offset buffer. The following proposed changes would be to implement an offset buffer in general rather than a specific forestry offset buffer.

Modify Section 95983. ~~Forestry~~ Offset Reversals.

(a) For ~~forest sequestration~~ **offset** projects, a portion of the ARB offset credits issued to the offset project will be placed by ARB into the ~~Forest~~ **Offset** Buffer Account.

(1) The amount of ARB offset credits that must be placed in the ~~Forest~~ **Offset** Buffer Account shall be determined as set forth in **the relevant** Compliance Offset Protocol ~~U.S. Forest Projects~~,

(2) ARB offset credits will be transferred to the ~~Forest~~ **Offset** Buffer Account by ARB at the time of ARB offset credit registration pursuant to section 95982.

(3) If a**n** ~~forest~~ offset project is originally submitted through an Offset Project Registry an equal number of registry offset credits must be retired by the Offset Project Registry and issued by ARB for placement in the ~~Forest~~ **Offset** Buffer Account.

(b) Unintentional Reversals. If there has been an unintentional reversal, the Offset Project Operator or Authorized Project Designee must notify ARB and the Offset Project Registry, in writing, of the reversal and provide an explanation for the nature of the unintentional reversal within 30 calendar days of its discovery.

(1) In the case of an unintentional reversal the Offset Project Operator or Authorized Project Designee shall, provide in writing: to ARB and an Offset Project Registry, if applicable, a verified estimate of current carbon stocks within the offset project boundary within one year of the discovery of the unintentional reversal.

(2) If ARB determines that there has been an unintentional reversal, and ARB offset credits have been issued to the offset project, it ARB will retire a quantity of ARB offset credits in the amount of metric tons of CO_2e reversed from the ~~Forest~~ **Offset** Buffer Account.

(c) Intentional Reversals. Requirements of the Offset Project Operator or Authorized Project Designee for intentional reversals are as follows:

(1) If an intentional reversal occurs, the Offset Project Operator or Authorized Project Designee shall, within 30 calendar days of the intentional reversal:

(A) Give notice, in writing, to ARB and the Offset Project Registry, if applicable, of the intentional reversal; and

(B) Provide a written description and explanation of the intentional reversal to ARB.

(2) Within one year of receiving the notice for intentional reversal from ARB the occurrence of an intentional reversal, the Offset Project Operator or Authorized Project Designee shall submit to ARB and the Offset Project Registry, if applicable, a verified estimate of current carbon stocks within the offset project boundary.

(3) If an intentional reversal occurs from a**n** ~~forest~~ offset project, the ~~forest~~ owner must replace each metric ton of CO_2e with a valid ARB offset credit or another approved compliance instrument pursuant to subarticle 4, within 90 calendar days of notification by ARB. Notification by ARB will occur after the verified estimate of carbon stocks has been submitted to ARB, or after one year has elapsed since the occurrence of the reversal

if the Offset Project Operator or Authorized Project Designee fails to submit the verified estimate of carbon stocks. If the ~~forest~~ owner does not replace each metric ton of CO2e within 90 calendar days of notification by ARB, ARB will retire a quantity of ARB offset credits in the amount of metric tons of CO2e reversed from the ~~Forest~~ **Offset** Buffer Account and the ~~forest~~ owner will be subject to enforcement action and each ARB offset credit retired from the ~~Forest~~ **Offset** Buffer Account will constitute a separate violation pursuant to section 96014.

(4) In the event of an early ~~forest~~ offset project termination ARB will retire from the ~~Forest~~ **Offset** Buffer Account a quantity of ARB offset credits in the amount calculated pursuant to project termination provisions in Compliance Offset Protocol~~, U.S. Forest Projects [DATE]~~. ARB will notify the ~~forest~~ owner of retirement within 10 calendar days. The ~~forest~~ owner must submit a valid ARB offset credit or another approved compliance instrument pursuant to subarticle 4 for each ARB offset credit retired by ARB from the ~~Forest~~ **Offset** Buffer Account within 90 calendar days of ARB's retirement. If the ~~forest~~ owner does not replace each ARB offset credit within 90 calendar days of ARB's retirement, they will be subject to enforcement action and each ARB offset credit retired from the ~~Forest~~ **Offset** Buffer Account will constitute a separate violation pursuant to section 96014.

(d) Disposition of **Offset** ~~Forest Sequestration~~ Projects After an Unintentional Reversal. If a reversal lowers the ~~forest~~ offset project's actual ~~standing live~~ carbon stocks below its project baseline ~~standing live~~ carbon stocks, the ~~forest~~ offset project will automatically be terminated by ARB or an Offset Project Registry.

(1) If the ~~forest~~ offset project is automatically terminated due to an unintentional reversal, another offset project may be initiated and submitted to ARB or an Offset Project Registry for listing within the same offset project boundary.

(2) If the ~~forest~~ offset project has experienced an unintentional reversal and its actual ~~standing live~~ carbon stocks are still above the approved baseline levels, it may continue without termination as long as the unintentional reversal has been compensated by the ~~Forest~~ **Offset** Buffer Account. The offset project Offset Project Operator or Authorized Project Designee must continue contributing to the ~~Forest~~ **Offset** Buffer Account in future years as quantified in section 95983(a)(1).

(3) If the ~~forest~~ offset project is terminated due to any reason except an unintentional reversal, new offset projects may not be initiated within the same offset project boundary.

Section 95985 Invalidation of ARB Offset Credits

Comment: In order to develop a well functioning offset market, buyer liability has to be significantly reduced. One way is to use the structure of the forestry offset buffer, but expand it to be a general offset buffer. The following proposed change would be needed to implement an offset buffer as described in Section 95983 above.

Modify Section 95985

(g) Requirements for ~~Forest~~ Offset Projects **contributing to the Offset Buffer Account**. If an ARB offset credit is found to be invalid pursuant to sections 95985(b) and (d) for a**n** ~~forest~~ offset project, the ~~Forest~~ Owner must replace each ARB offset credit with a valid ARB offset credit or another approved compliance instrument pursuant to subarticle 4, within 90 calendar days of being notification by ARB pursuant to section 95985(e). If the ~~Forest~~ Owner does not replace the invalid ARB offset credit within 90 calendar days of being notified by ARB pursuant to section 95985(e), each outstanding ARB offset credit will constitute a violation pursuant to section 96014.

Section 96014. Violations.

Comment: The basic penalty amount per violation under Health and Safety Code § 40402(b) is up to $10,000. At this amount, potential penalties for each ton in violation are 250 to 1000 times higher than the range of allowance prices. Such penalties are extreme and may have significant market impacts. Changing the penalty to “per 1,000 instruments” limits the number of violations and yields penalties that are more reasonable when added on top of the 4-1 excess surrender requirement. The 45-day period was referred to at page 41 of ARB’s summary of the 15-day changes: “The section was also clarified to allow the violation to accrue every 45 days instead of each day the compliance instrument remained unsurrendered.” The 45-day period should be included in the regulation.

Modify Section 96014

Section 96014 (a) If an entity fails to surrender a sufficient number of compliance instruments to meet its compliance obligation as specified in sections 95856 or 95857, and the procedures in 95857(c) have been exhausted, there is a separate violation of this article for each 1000 required compliance instruments, or portion thereof, that haves not been surrendered, or otherwise obtained by the Executive Officer under section 95857(c).

Thank you for the opportunity to provide these comments.

Sincerely,